Exhibit 100

To: Colglazier, John[John.Colglazier@anadarko.com]; Smith, Jeremy[Jeremy.Smith@anadarko.com]; Fielder, Robin[Robin.Fielder@anadarko.com]; Gamble, Meredith [Meredith.Gamble@anadarko.com]; Christiansen, John[John.Christiansen@anadarko.com]; Moreland, Stephanie[Stephanie.Moreland@anadarko.com]; Newman, Juanita [Juanita.Newman@anadarko.com]
From: Hatley, Tracey[/O=APC/OU=DOMESTIC/CN=RECIPIENTS/CN=SDQ403]
Sent: Fri 11/13/2015 2:55:00 PM Coordinated Universal Time
Subject: Fwd: Transcript From The Jefferies 2015 Energy Conference
Attachment: jeff91.apc.doc
Attachment: ATT00001.htm

Tracey Hatley
Anadarko Public Affairs & External Communications
Office: 832-636-1216
Mobile: 832-928-7348
Fax: 832-636-0130
www.anadarko.com

Begin forwarded message:

From: Wall Street Webcasting <conferences@wsw.com>
Date: November 13, 2015 at 8:42:20 AM CST
To: "Hatley, Tracey" <tracey.hatley@anadarko.com>
Subject: Transcript From The Jefferies 2015 Energy Conference

Hi Tracey,

Attached is APC's transcript, from the **Jefferies 2015 Energy Conference**. Please let me know if you have any questions, or if I can help you with anything else.

Kind regards,

Cathleen

Cathleen Rogalsky

Ext: 804

Wall Street Webcasting
P: 201.683.2100
F: 201.850.1944
conferences@wsw.com

On Wed, Nov 11, 2015 at 11:38 AM, <tracey.hatley@anadarko.com> wrote:

Webcast Registration

Jefferies 2015 Energy Conference

Invoice ID: c52339b9-8a54-4ebf-9ddc-de3d6ae2ee94
Date: 2015-11-11 11:38:00
Status: This order is to be INVOICED.
Tracey Hatley
Anadarko Petroleum Corporation
1201 Lake Robbins Drive
AI.R29036
Spring, TX - Texas 77380
Email: tracey.hatley@anadarko.com
Phone: 8329287348
Transcript
Add Transcript $125.00
Total Due: $125.00

x_clear_shopper	1
x_comment	
x_company	Anadarko Petroleum Corporation
x_con_email	tracey.hatley@anadarko.com
x_con_name	Tracey Hatley

Exhibit 329

x_description	Conference Webcast Registration
x_event	jeff91
x_event_date	November 11-12 2015
x_group_id	129
x_replay	90
x_skip_msg_internal	
x_skip_msg_invoice	
x_skip_msg_receipt	
x_ticker	APC
x_title	Jefferies 2015 Energy Conference
x_update	

Company Name: Anadarko Petroleum Corp. (APC)
Event: Jefferies Energy Conference
Date: November 11, 2015

<<Jonathan Wolff, Analyst, Jefferies & Co.>>

You ready? Test. Good morning, everyone. Welcome to the Jefferies Energy Conference. I'm Jon Wolff, follow the producers here. Excited to have Anadarko with us. Speaking today is Ernie Leyendecker, who's Senior Vice President of International Exploration. Thanks a lot for coming, guys.

<<Ernest Leyendecker, Senior Vice President of International Exploration>>

Thanks, Jon. I appreciate that. I guess, first off I want to start off by recognizing what day it is and thanking all of our veterans and I would encourage all of you guys to do the same. Those men and women do a lot for us to allow us to live the quality of life that we do in this country. So I think on behalf of Anadarko I just want to start with that.

And then secondly, I thought this was a great opportunity to bring you back to the asset portfolio today in spite of a lot of noise around the equity over the last 24 to 48 hours. And honestly, my purpose today was really to kind of walk you through the assets and talk a little bit about how we see things that differentiate us and our competitive advantages and talk to you about some of the way we think about capital allocation and why we do what we do.

So, anyway, let's get started. Of course, I want to start out with our obligatory cautionary language slide. A little bit of this presentation will include some forward-looking statements and I encourage you all, of course, to go look at our most recent 10-Q.

And so, starting with the first deck, and many of you would have probably seen this slide before, this really is the story of what we believe differentiates Anadarko. We have continuously thought about managing through the cycle for a number of years now, particularly important in the current environment we're in. We continue to think about how we maintain flexibility. We build and we preserve value for the future and lay a foundation as we come out of the current cycle that we're in.

And we will, as we've talked about, allocate capital this year and next year to stay within our cash inflows. So we've been very financially disciplined over the past number of years. I'm sure most of you are aware of that and I think that has served us well and we will continue to look in that direction for the near-term.

So a couple of things just to point out that I have on my notes here. Really, we're going to be focusing on moderating our base decline, improving efficiencies and productivity. You've heard us talk about a number of things relative to some of our onshore assets and efficiency gains. And we'll continue to focus on reducing costs. Meanwhile, we're going to still allocate capital to our long cycle, international and deepwater exploration because that's what we do. We explore.

So, turning over to our track record slide, this really is an illustration of our key accomplishments over the past five years or so. We have – we really believe we have delivered sustainable, reasonable compounded growth and some free cash flow over the last five years. We have replaced our production at competitive metrics. We have had, as most of you know, some extraordinary success in terms of exploration and retained quite a bit of resources after all that investment in exploration.

And we talk about being very active managers of our portfolio. And you see on the bottom of the slide, over the course of the last five years, the enormous amount of monetizations, which we have done. Most notably, of course, this year, we've monetized nearly $2 billion worth of assets, various parts of our asset portfolio. We like to think of that as one of our competitive advantages. We look at our diversified portfolio, and where we see it doesn't fit, we look for opportunities to bring value forward and redeploy the capital into more efficient places in our asset portfolio.

So what to expect in 2015? You've seen a lot of these numbers before. The thing about this particular slide is it really illustrates what differentiates us in terms of our diversified asset portfolio, which is there's kind of a hidden formula in this slide in terms of an equation of our diversified portfolio, particularly offshore and international provides us a little bit lower base decline rates, which equals less maintenance capital.

So as you look at the chart on the upper right-hand side of the slide and you look at our 2015 estimates, you see we only need about $2.7 billion to maintain our flat or nearly flat growth. And you see the green bar on the slide has been taken out. That's what gives us the optionality, the offsetting lower decline assets, high-margin things in the deepwater Gulf of Mexico and international.

So I think the formula works for us. I want to make sure people understand that we think about that as a competitive advantage. And it's – the distinction here is that we're not just a pure play U.S. onshore in one or two key basins. We like that and I think that's significant and important to point out.

As I said, our focus will continue to be on preserving value and flexibility for the future in this period of lower commodity prices. We're going to be judicious with our capital allocation. We're going to reduce our capital spending to match our cash inflows and that is significant. Not discretionary cash flow, but cash inflows. And we're going to reduce our relative capital allocation to the short cycle part of our portfolio.

So the bottom part of the slide is really how we think about allocating capital at Anadarko. And many of you have probably heard on multiple occasions how we talk about capital allocation is one of the things that we think is key to success, that along, of course, with an important corporate culture. But we believe, management teams that allocate capital and have the flexibility to press on the accelerator, or step on the brake, and put the capital to work to generate returns in the best assets in the portfolio are really one of the things that differentiates us.

The short cycle component of this slide on the left hand side, we don't think you're being rewarded for growth in today's environment. So, we're going to redeploy some of that into our mid-cycle and our longer-cycle assets because we think there's additional option value and value to create in funding those types of assets, particularly exploration and the major projects that we have going on in the pipeline, which I'll talk about in a few minutes.

So flipping over to a snapshot of our U.S. onshore portfolio, I took a look at this again yesterday and one of the most striking things to me, really, when you look at it is not only have we been increasing our liquid volumes over the past five or six years, but if you actually look at this over the past six years, we have had four times liquid volume growth, which is really remarkable, from back in 2009. And I think that is an entire small-cap company in and amongst itself. And I think that's the story here.

This is the competitive advantage of having a position in the Wattenberg in the DJ, having a position in the Eagle Ford, having a position in the Permian Basin, and particularly at Delaware, having a position in East Texas and in the Marcellus. It has given us the operational flexibility to really move capital around to where we think we can generate the highest returns.

And I think it's a clear demonstration of our track record and the assets, and the asset team's ability to execute when and if we can return into a growth mode when we think we're going to be rewarded for growth.

Kind of the highlights, really, today, as most of you are probably aware, are our Delaware position. I have a slide on that in a minute. But when you look at the Delaware today, we continue to learn things that really get us excited. It is starting to become as attractive as our Wattenberg assets and it will continue to attract capital going forward.

And as you'll see, we are going to be in a bit of a maintenance mode out there, trying to build for the future, building out the backbone of infrastructure as we have done in our other basins like in the DJ and in the Eagle Ford.

So I've got a few slides on these assets. Wattenberg, this is my Wattenberg rock slide. I'm sure many of you have seen a lot of our information around Wattenberg, but going back to one of the reasons I'm happy to be here is talking about our competitive advantages. Wattenberg is really an enormous resource with a tremendous amount of running room that delivers material returns even in today's environment. You've watched us really build out our infrastructure and get ahead of it, taking advantage of our position, a large acreage position in the Wattenberg where we have advantages with royalty, infrastructure, the size and the scale, and the inventory really is just remarkable.

A lot of times we pointed out this little bar chart on the bottom of this slide really that illustrates the uplift we get from being a fee mineral owner. In today's environment, we really are getting a really material uplift because we are a fee mineral owner up to as much as 50% of PV in today's price environment. So Wattenberg is going to command a very large portion of our maintenance capital to keep that machine running and position ourselves for the future when we can step on the gas.

Turning to South Texas, this is our Eagle Ford slide. I think the most exciting thing about Eagle Ford in relating it to our competitive advantages really is all about execution. In about five or six years' time, we took a position in the Maverick Basin and we exploded it from virtually zero to 275,000 barrels a day, which is an absolute machine, an incredible testament to the field operating guys and the execution team, and really a perfect example of how Anadarko utilizes our strengths and our competitive advantages to generate material returns for our shareholders. And I think that's probably the coolest thing about the Eagle Ford for us today.

If I looked at really one of the up and coming stars in our asset portfolio in the U.S. onshore, it's the Delaware Basin. We've talked about it and many of you've heard a lot about it. Really, the Permian is, in my humble opinion, the basin that keeps on giving. It's one of those few basins in the world that we like to go back to. We love the basin.

We have a significant position. Over 600,000 gross acres in the sweet spot, in an over pressured area. We continue to see great performance out of our program. It's a very large resource with a considerable amount of running room. And I think some of the competitive advantages for us in the Delaware Basin really are the fact that it is a stack play.

We're not just looking at the Wolfcamp A, we've got multiple benches. We continue to work through those benches. We're seeing wells now approaching 1 million barrels of oil equivalent per day. We're testing the Second Bone Spring. We recently had a well that had an initial IP of more than 1,000 barrels a day. And really, as we sit here today, we're trying to lay the foundation for growth in the Delaware Basin, because it's a fairly remote area.

You can see a number of things listed on the slide that we're doing to prepare for full-scale development. We're looking forward to the day when we can go to pad drilling, which will allow us to continue to drive down costs. We've driven down drilling costs over the last recent year down to about $7.5 million and we think there's another $1.5 million or $2 million to go on that efficiency when we move into the pad drilling process. And again, in terms of competitiveness, you see that Delaware is delivering very strong returns for us in today's price environment.

So shifting gears just a little bit from the U.S. onshore to talk a little bit about our mega projects and our competitive advantages. I mentioned a little bit about our international deepwater Gulf of Mexico production assets. Really, these mega projects I think of as a differentiator because they balance our portfolio in that, as I said earlier, the base declines are different from conventional reservoirs than they are from the unconventionals and they help us moderate our base decline.

We've got a significant competitive advantage and a strong track record over a long number of years operating very large major capital projects. We call them mega projects, particularly in the Gulf of Mexico, North Africa and Algeria, and in Ghana. These assets deliver high-margin oil, typically indexed to Brent, or slightly discounted to Brent, if it's in the Gulf of Mexico. And you see on the slide, the build of – the stack build of a lot of the historical track record we've had going back to our discovery in Ghana, Jubilee, and then a number of Gulf of Mexico assets in there.

Layered on top of that, of course, is the forward-looking Mozambique deliveries out towards the end of the decade. So this is a cool slide. And really, it demonstrates how we're able to utilize these competitive advantages in terms of project management and major projects and fit within the Anadarko asset portfolio.

Gulf of Mexico, this – the Gulf continues to deliver for us. We've been in the Gulf for a long time, Anadarko and/or our legacy companies. And quite frankly, we have a distinct competitive advantage in the Gulf of Mexico, and that gives us a differentiation. We've been incredibly successful and blessed with good fortune on the exploration side in the Gulf of Mexico, which has underpinned a lot of our volumes today and historically. We know the Gulf. We know exploration in the Gulf. We understand pre-salt or above salt. We sub-salt.

I've talked about our project management skills. We continuously benchmark as a best-in-class, low cost, on time, on budget project deliverer. A couple of highlights on the slide you see. The Lucius field came online earlier this year. It's producing 80,000 barrels of oil a day, a remarkable achievement and accomplishment and we're very proud of that. The infrastructure advantage that something like Lucius gives us is really difficult to grasp without talking about the rest of the infrastructure that you see on the blue ocean – in the U.S. Gulf, with all of our infrastructure in and about the Gulf of Mexico.

We're well on our way to get Heidelberg on delivering volumes in mid-2016, another fabulous discovery, which we have moved forward with. And, of course, not to miss out on the Shenandoah Basin, which is somewhat near and dear to my heart, as I used to be responsible for the U.S. Gulf deepwater exploration program, remarkable discovery, and recently another appraisal well, which we found over 620 feet of oil pay full to base, and we are currently in the process of doing a bypass core on that. So the Gulf really is still an important part and it delivers very high margin barrels, and as I said, offsets our declines with conventional decline rates in the Gulf.

So here's, turning to the international assets, often sometimes overlooked, but really they're remarkable in and amongst themselves. You see a few highlights on Ghana and Algeria. The key thing really is our international offshore opportunities provide us some high-margin oil. Jubilee, unbelievable story. We brought it online in about three and a half years. Currently it has surpassed 125 million barrels of oil equivalent, still a very, very large resource in expected ultimate recovery. Continuing to work the field – moving into phase two at Jubilee.

Next door to it are Tweneboa, Enyenra and Ntomme field should be progressing towards first production sometime next year and we're looking forward to that. That'll add some more high-margin barrels as we look to 2016. And then, a lot of milestones really around Algeria that don't seem to get enough attention in my humble opinion. We have produced out of our three assets in Algeria over 2 billion barrels of oil. That's just incredible. And I think it's a bit overlooked. These type of things really give us margin uplift in terms of our EBITDAX per barrel equivalent, and then phenomenal assets. We love the optionality of having international developments and production in our asset portfolio.

So let's flip to Mozambique quickly because I'm running out of time here. Really, you've heard this many, many times, we're a world-class asset, obviously one of the largest gas resources discovered in the last 25 years or so. So bringing it back to our competitive advantages, realistically, this is right in our wheelhouse in terms of deepwater.

Project execution, as I've talked about, we have a number of cost advantages in Mozambique because we're close to shore. We believe we're proximal to the Asian markets. And we've talked about the reservoir quality and the potential deliverability of these wells being in excess of 100 million cubic feet a day.

So when we think about Mozambique, and you think about Mozambique, it is a very attractive for buyers in the market – in the LNG market because really it's a very large resource. It's close to the premium markets and it has a number of cost advantages in terms of – it is going to be one of the low cost LNG providers out there in the future, a long-term stable supply of LNG.

Let me take you for a quick spin around the world in terms of exploration, which is closer to my world, starting with the Gulf of Mexico. You've probably heard earlier this year, we announced a discovery called Yeti. We are back out of Yeti drilling another well today. I already mentioned the remarkable Shenandoah accomplishments. We drill the well to test the up-dip part of the basin, we found it, and we sidetracked and we're cutting a core. We continue to do high-impact exploration in the U.S. Gulf and we will continue to do that in the future.

But international is another exciting part of our asset portfolio today. We announced early discovery in Colombia at our Kronos well. We're very excited about that. We are drilling our second frontier exploration well in deepwater Colombia called Calasu. It's actually about 100 miles away. More to come on that.

But as exciting as that is, we're also shooting an extremely large 3D on a 16 million acre series of blocks, which is going to be one of the largest 3D shot in the world, almost 29,000 square kilometers. And if I put this into context for some of you who understand geography, that is about the size of one and one-third of the U.S. Gulf of Mexico protraction areas, or about as big as the entire Delaware Basin. So we're very excited in international exploration to be able to have the first look at brand new, modern 3D over a frontier area in deepwater Colombia.

I would be remiss if I didn't tell you a little bit about our excitement around our Paon discovery in Côte d'Ivoire. As soon as we're finished in Colombia, we'll be moving the rig back to Côte d'Ivoire to drill yet another well on our Paon discovery. We will subsequently sidetrack one of the existing wells, put some gauges in it, down-dip, put some gages in a well up-dip and do a drill sim and interference tests on that well.

And then after that, we've got two more exciting exploration opportunities right adjacent to that in some contiguous blocks where we recently secured a block that really forms a four-block area between our CI-103 and CI-527, CI-528 and CI-529 where we'll be doing some more exploration. So looking forward to that.

Probably my favorite slide in the deck, because I'm the explorationist here, is – illustrates really our competitive advantage to exploration and how we think about creating value and option value. So you see over the past 10 years or so, we have invested about $10 billion. We have discovered a material amount of resources. But more importantly, we've monetized $13 billion worth of assets and retained a significant amount of resources, but also roughly 250,000 barrels equivalent per day. So it's a remarkable story for Anadarko. It's extraordinary. We're happy and we really believe that investing for the long-term in long-cycle opportunities provides us this optionality and this value.

So I won't spend much time on this. Really, this is all about our balance sheet and a snapshot of it. Most of you that. It really gives you a flavor for our sources of cash, our credit rating and really some examples of how we are able to generate liquidity through active portfolio management, as we've talked about this year's monetizations in total, including WES TEUs, and secondary offerings has been almost $2 billion. So we believe the strength of our balance sheet and our ability to monetize assets in our portfolio and the leverage we have in the LP space gives us lots of optionality to really think about where we are in the current environment for the long-term.

And I think with that, I will end on our last slide and kind of hit back on our key theme and remind you that our view today really is all about building and preserving value for the future and positioning ourselves to come out of this hopefully in the near-term.

And with that, I will entertain some questions.

Q&A

<Q – Jonathan Wolff>: I'll start with a couple. One on the [indiscernible] the moderation of the decline rate [indiscernible]?

<A – Ernest Leyendecker>: So I think the natural occurrence that's going to happen as we brought on deepwater projects like Lucius and as we look to bring on deepwater projects like Heidelberg is that that's going to give us a bump. Obviously, in 2015 and 2016, it's going to offset that. But really our focus on the U.S. onshore side is to look at the base decline today. Drive efficiencies into the model, make sure we're taking care of the base decline, and proportionally allocate capital away from the short-cycle things, because we don't believe you're rewarded for growth in today's price environment.

<Q – Jonathan Wolff>: And then a quick one on Mozambique. [indiscernible].

<A – Ernest Leyendecker>: Absolutely. That's a great question and point. We recently awarded the onshore LNG contract to a consortium of three. We actually got back to tenders that showed we were going to be able to build two 6 million ton per annum trains for the same price we thought we were going to get two 5 million ton per annum train. So the current cost environment is very conducive for major projects. Steel prices are down. And it's a great opportunity to be in, if you have the capital to build to allocate to it, major projects. So thrilled about that and more to come. And as far as the project financing, I probably skipped over it on the slide, but you can see

– if you flip back you can probably see that we have secured about 60% LOIs towards our project financing for the LNG project.

<Q – Jonathan Wolff>: Maybe another one on Mozambique. On Mozambique, a lot of questions around customer demand with obviously Australia coming on and China slowing a little bit [indiscernible].

<A – Ernest Leyendecker>: Well, I think we all recognize there's some pressure obviously on global LNG supply and prices, but I think the thing that we like about our Mozambique position really is that we believe it is going to be competitively advantaged because it's a low cost project, one of the lowest cost, if not the lowest cost, probably in the world, and I think that makes it attractive. That with the large resource base is going to attract the premium buyers who are going to want to position in that long-lived asset that is very cost-efficient for us to develop and deliver.

<Q – Jonathan Wolff>: How are you guys thinking about distressed [indiscernible]?

<A – Ernest Leyendecker>: Well, I guess as witnessed by the last 48 hours or so, we're always looking at things to be quite honest with you. We're always looking to see what might be available. We're always looking at our own internally – at our own portfolio to see what's not attracting capital. And if it's not and it's not competitive, we're looking to find the most value for it. So we've talked a number of times about building a better company, not necessarily a bigger company. We've always thought about bolt-on assets and we will continue to look at that if it works for us. Yeah. [indiscernible]

<Q – Jonathan Wolff>: Are you looking for – you wanted to grow your international assets. What was the rationale behind it? I mean it seems like you have a pretty good organic growth story going and you mentioned some of the opportunities. [indiscernible]?

<<Ernest Leyendecker, Senior Vice President of International Exploration>>

Well, I think we're always looking to build a better portfolio, to be honest with you. The recent news, obviously, you've all probably read it by now. I really wasn't prepared to talk a lot about the details of that here today. I think it's still quite fresh and it's fairly self-explanatory, if you look at the release this morning. And I think I'll leave it at that because we don't comment on M&A.

<<Jonathan Wolff, Analyst, Jefferies & Co.>>

I really appreciate your time this morning. Have a great day.

Exhibit 101

S&P Global
Market Intelligence

Anadarko Petroleum Corporation
NYSE:APC
FQ4 2015 Earnings Call Transcripts

Tuesday, February 02, 2016 2:00 PM GMT

S&P Global Market Intelligence Estimates

	-FQ4 2015-			-FQ1 2016-	-FY 2015-			-FY 2016-
	CONSENSUS	ACTUAL	SURPRISE	CONSENSUS	CONSENSUS	ACTUAL	SURPRISE	CONSENSUS
EPS Normalized	(1.09)	(0.57)	NM	(0.94)	(2.45)	(2.00)	NM	(2.90)
Revenue (mm)	1963.55	2053.00	▲4.56	1887.69	8628.76	8698.00	▲0.80	8531.32

Currency: USD
Consensus as of Feb-02-2016 12:04 PM GMT

- EPS NORMALIZED -

	CONSENSUS	ACTUAL	SURPRISE
FQ1 2015	(0.62)	(0.72)	NM
FQ2 2015	(0.52)	0.01	NM
FQ3 2015	(0.74)	(0.72)	NM
FQ4 2015	(1.09)	(0.57)	NM

Table of Contents

Call Participants

EXECUTIVES

A. Scott Moore
Former Senior Vice President of Midstream & Marketing

Darrell E. Hollek
Former Executive Vice President of Operations

James J. Kleckner
Former Executive Vice President of International and Deepwater Operations

John M. Colglazier
Investor Relations Professional

Mitchell W. Ingram
Executive Vice President of International, Deepwater & Exploration

R. A. Walker
Chairman & CEO

Robert G. Gwin
President

ANALYSTS

Brian Arthur Singer
Goldman Sachs Group Inc., Research Division

Charles Arthur Meade
Johnson Rice & Company, L.L.C., Research Division

David Martin Heikkinen
Heikkinen Energy Advisors, LLC

David Robert Tameron
Wells Fargo Securities, LLC, Research Division

Douglas George Blyth Leggate
BofA Merrill Lynch, Research Division

Edward George Westlake
Crédit Suisse AG, Research Division

Eliot Casper Javanmardi
Capital One Securities, Inc., Research Division

Evan Calio
Morgan Stanley, Research Division

Harry Mead Mateer
Barclays Bank PLC, Research Division

Jeffrey Leon Campbell
Tuohy Brothers Investment Research, Inc.

John Powell Herrlin
Societe Generale Cross Asset Research

Paul Benedict Sankey
Wolfe Research, LLC

Phil Corbett
RBS Strategy

Robert S Morris
Citigroup Inc, Research Division

Ryan M. Todd
Deutsche Bank AG, Research Division

Scott Michael Hanold
RBC Capital Markets, LLC, Research Division

Presentation

Operator

Good morning, and welcome to the Fourth Quarter 2015 Anadarko Petroleum Corporation Earnings Conference Call. [Operator Instructions] Please note, this event is being recorded.

I would now like to turn the conference over to John Colglazier. Please go ahead.

John M. Colglazier
Investor Relations Professional

Thank you, Emily. Good morning, everyone. We're glad you could join us today for Anadarko's Year-end 2015 Conference Call.

I need to remind you that today's presentation includes forward-looking statements and certain non-GAAP financial measures. We believe that our expectations are based on reasonable assumptions. However, a number of factors could cause results to differ materially from what we discuss today. So I encourage you to read our full disclosure on forward-looking statements and the GAAP reconciliations located on our website and attached to last night's earnings release. Additionally, as we always do, we've provided more detail in the quarterly operations report on our website.

I'd like to take a moment and thank Robin Fielder for the contribution she's made to the IR team and her efforts over the last 1.5 years. She's transitioning back to the operations group, and Shandell Szabo, a geologist with experience across the company, is joining our team. And she's looking forward to taking your calls after the call today.

At this time, I'll turn the call over to Al Walker, and we'll open the lines in a few minutes for Q&A, with Al and our executive team, following his remarks. Al?

R. A. Walker
Chairman & CEO

Thanks, John. And I'd also like to take a moment and just say, Shandell, welcome to the organization that John has built, and also introduce Mitch Ingram. Many of you know that Mitch joined us in the fourth quarter of last year as EVP of LNG, coming to us from BG Group, where he's an Executive Vice President of the technical aspects of the company as well as a member of the Executive Committee. Mitch's background with BG includes accomplishments, most noteworthy is the accomplishment he achieved associated with our Queensland Curtis LNG project.

Additionally, I'd like to say how proud I am of our employees who served and proved more than once in the challenges of last year just how great they were at navigating the uncertain price environment we anticipated as we entered 2015. Through their combined efforts, we outperformed our initial expectations by increasing our higher-margin oil sales and volumes while spending significantly less capital and improving our cost structure and enhancing efficiencies. We also closed $2 billion of monetizations.

Additionally, during the year, we reduced our capital spending by almost 40%, and oil prices fell by almost 50% over that time horizon. We organically replaced more than 130% of our production with reserve additions at a cost of about $14 per BOE. We also significantly increased the percentage of our reserves and improved developed category to 80% at year-end 2015 compared to 30 -- compared to 69% at the end of 2014. These achievements position us well to manage through the market's uncertainty and volatility we see in the coming years.

As I mentioned in last night's news release and later this month, we will recommend a capital program to our Board that reflects our view of 2016 and beyond. Our preliminary expectation is that APC will spend about $2.8 billion this year, which is roughly half of what we spent in 2015 and 70% less than our expenditures in 2014. As stated on other occasions, we will favor value preservation and allocating this capital, and as such, our short-cycle U.S. onshore investments would be impacted the most.

Frankly, even with 2 of the best assets in North America, we don't find the returns in this environment to be compelling. Therefore, we are choosing to fund a reduced program in the Wattenberg field and only a delineation and lease preservation program in the Delaware Basin as we seek to preserve these shorter-cycle opportunities for a better day.

Even with these reductions, our total sales volumes across the company are expected to only decline by 1% to 4% on a divestiture-adjusted basis, with lower margin gas volumes accounting for all of the declines. We expect to keep our divestiture-adjusted year-over-year oil sales volumes and the year-over-year Q4 exit rate oil production relatively flat.

Given our materially lower capital plans for 2016, this is very noteworthy and a result of exceptional efforts by our employees. We plan to achieve this through starting the production of the Heidelberg spar much earlier than expected, continued outperformance at Lucius, the TEN complex in Ghana coming online as expected in Q3 and an increased focus on our GOM tieback opportunities.

Leveraging our infrastructure enables us to deliver these incredibly capital-efficient tieback opportunities, which we believe generate rates of return of 30% to 100% even at today's prices. We will also continue to seek innovative ways to monetize assets this year. We already have greater than $1 billion of monetization opportunities that are at very advanced stages, with no current plans to monetize more of our ownership in WGP in this environment.

As we have done historically with great success, we plan to continue actively managing our portfolio this year and have other monetizations identified, which will be pursued through the course of the year. The quality of our balance sheet remains a key objective. With the flexibility provided by our reduced capital program, the ongoing benefits of an improved capital and cost structure and our pathway to several near-term monetizations, we are very confident in our ability to maintain or decrease Anadarko's net debt levels this year while spending well inside of our cash inflows.

We look forward to going into greater detail about our capital plans and expectations for 2016 on our March 1 call, which we look forward to doing as soon as possible, but March 1 will be here soon enough.

During these times and more than ever, our company's culture, its employees, its track record and its approach to value creation matter, and we believe these are all competitive advantages for Anadarko. With that, we'll open it up for questions.

Question and Answer

Operator

[Operator Instructions] Our first question is from David Tameron of Wells Fargo.

David Robert Tameron
Wells Fargo Securities, LLC, Research Division

Al, I think you just addressed it there, but obviously, the big concern of the market's been the ability to maintain your investment-grade status, and that's caused a lot of noise in the share price. Any more detail you can give? It sounds like you got $1 billion teed up and what else. Can you give me a color around that?

R. A. Walker
Chairman & CEO

Yes, David. I think we see the over $1 billion of monetizations doing a lot to address the question of how we're going to fund this year activities with cash. And Bob's been spending most of the quarter, to date, with lots of different issues associated with the question you're asking. So I probably will, if you don't mind, defer that question to him.

Robert G. Gwin
President

David, great question. Obviously, everybody has seen that both agencies have taken down their price cases again. Moody's placed essentially the entire sector on review. We've provided them some preliminary numbers. We're going to continue to work with them in the coming weeks and coming out of our Board meeting next week to make sure they have the most recent and updated information available. This is all part of normal course this time of year, although, usually, all that is done after our investor call. And we would hope and expect that the agencies are going to apply their historic standards and their historic methodology in their current analysis. And on that basis, if they do so, we believe that we're soundly investment-grade. And will become even more so as we execute the 2016 plan and the monetization beyond that initial $1 billion-plus that Al referred to. Obviously, there's a lot of folks that are talking to the agencies, a lot of rumors out there. We can't predict at this stage what we think their actions are going to be. We can only control the things we can control. But we believe that the plan that we have, easily identifiable and transparent, maintains an investment-grade rating with all 3 of the agencies and puts us in a position to continue to execute the plan and refinance the debt that's coming due later this year.

David Robert Tameron
Wells Fargo Securities, LLC, Research Division

Okay. I have one follow up, and I'll jump to ops. And thanks for the color on that. If I think about short-cycle and think about the Gulf of Mexico, can you just tell me -- obviously, short-cycle U.S. production. But how do we think about Gulf of Mexico startup there, kind of what volumes you're going to be adding there? And nice to know if there's still -- those -- will some of the tiebacks be still in the plan for 2016?

R. A. Walker
Chairman & CEO

David, very understandable question, and I think you can appreciate that what we're trying to do today is paint the picture for more details that will come in March. But I think Jim could give you an example of a tieback opportunity, just to give you some color around the black-and-white.

James J. Kleckner
Former Executive Vice President of International and Deepwater Operations

Yes. This is Jim. And let me just give you a brief overview of some of the fields that we have. We have fields that are closed infrastructure that we can tie back at relatively low cost. One of them is Caesar/Tonga, and this field ties back our Constitution spar. It has a ribbonlike structure with a lot of undeveloped reserves that, for relatively low costs, we're able to drill and complete and tie back quickly. Our wells produced upwards from 6,000 to 10,000 barrels a day. So Caesar/Tonga offers those tieback opportunities, and we have 2 wells. One has been drilled and is in the completion phase. The other one has been drilled and will be completing here into 2016 and bringing that on production here in the third quarter of '16. So that's an example of some of the tieback opportunities we have that are relatively short-cycle.

Operator

Our next question is from Doug Leggate of Bank of America.

Douglas George Blyth Leggate
BofA Merrill Lynch, Research Division

Al, the whole Anadarko investment case has, I guess, been predicated over the years with the balance you've had in your portfolio between short-cycle and long-cycle projects. In this environment, how do you plan or pace or think about the things like Shenandoah, Yeti, Paon, Mozambique, given the uncertainty in the oil price? How do you think about how you continue to execute on those and basically get market recognition for the value?

R. A. Walker
Chairman & CEO

Well, Doug, as always, you ask really good questions, and I appreciate your question a lot. I think as we think about 2016 and taking the comment that's been made about trying to preserve value, when you consider that-- I believe this year, we would estimate that our maintenance CapEx is going to be about 2/3 of what it was in the prior year for maintaining volumes. If you couple that with -- we anticipate our oil volumes being relatively flat through the year that only the decline we see on a divestiture-adjusted basis is coming from gas. We believe that at some point, when growth matters again, we're prepared to go back to growth. But I think by lowering that maintenance CapEx 2/3 or 2/3 rather of what it was the prior year, that's pretty impressive in terms of being able to create that value preservation that we're looking for. I think these other longer-data projects, we believe, today, are worthy of spending capital, expecting that oil is not going to be at $30 for the rest of our life. And at some point, when we make a decision to take either to sanction or FID any of these longer-dated projects, it will be in an environment which we believe we can recommend to our Board first that we make that investment. So I think that's the confidence I would have if I were an investor, that we will do that when it's appropriate.

Douglas George Blyth Leggate
BofA Merrill Lynch, Research Division

I appreciate it, Al. I'm probably going to get in trouble with Mr. Colglazier for this one, but I'm going to have a go anyway. This is the first call you've had since the events of November. I know that there's obviously some issues around debt maturities and stuff like that, that, perhaps, some people think is weighing on the balance sheet-- or on the share price. Our feedback is probably just as much about whether there's still an active acquisition appetite at Anadarko. So I wonder if you could maybe just take a minute to just give us an explanation as to why you have thought the Apache deal was attractive to Anadarko. Could those concerns go to rest once for all. I'll leave it there.

R. A. Walker
Chairman & CEO

Okay. Well, I thought you were probably talking about the MLP meltdown in November. I didn't anticipate you were going to ask about the other. I think, really, the comments that we made back in November associated with the press release that day is about all I have to say on that matter. There really is nothing else that I can add to it. In addition, I think we continue to make the comment or reaffirm here, the acquisitions that we're most interested in have to do with areas that we have focused areas

of concentrated operations, be that in the DJ Basin or in the Delaware Basin, very competitive places in which we buy things. But those are the focus that we would have today. But I also believe that the things that we're trying to do to take 2016's environment and making the most out of it is probably the most important agenda at hand. I think getting through this year, being able to keep our oil volumes flat on a divestiture-adjusted basis, the only reduction we see in volumes coming through gas properties that we're not investing in, in this market, those are the things that, I think, we will do this year while preserving the balance sheet and looking at it as a key objective for improving the quality where we can. Because I made the comment earlier and I'll reaffirm here, I think we believe we can maintain net debt at a level that it's at today, if not reduce it further, while still meeting the capital objectives that I laid out this morning.

Operator

Our next question is from Evan Calio of Morgan Stanley.

Evan Calio
Morgan Stanley, Research Division

Impressive cuts here. A follow-up on the monetization program, the $1 billion that you referenced to me. Are those producing assets? And could you provide any color on the asset market and then your confidence and ability to execute in '16?

R. A. Walker
Chairman & CEO

Well, let me just say, at March 1, we'll go into a lot more detail. But let me -- since all that reports into Bob, let me refer to him on that one.

Robert G. Gwin
President

I think without going into detail, some of the assets that we are looking to monetize in the near term are producing assets, some of them are not. And it'll take greater shape as we announce them either -- at March 1 or between now and March 1. I think it's fair to say that these aren't -- these are -- these assets generally share the characteristic of our asset sales in the past, and that is that they have sound economics but not economics that rise to the point that they would get funded relative to our other portfolio opportunities over virtually any commodity cycle. And so much like the assets that we sold last year and monetizing $2 billion, they're not things that are going to be material to the company's future, limit the company's growth or they may not be of the size that's material to a company of our scale and our expectations for the future. So we've got a long list of them, but as Al mentioned, there are some that are near term, higher probability that we feel very comfortable in executing and, when added to our discretionary cash flow, would exceed the $2.8 billion number that we talked about today.

Evan Calio
Morgan Stanley, Research Division

That's great. Could you also provide some color on your DUC completion strategy assumed in this flattish production profile and significantly lower CapEx? Are those assumed deferred like you're drilling program? Or is there any change there as you think about 2016?

Darrell E. Hollek
Former Executive Vice President of Operations

Evan, this is Darrell. Yes, as we look at our iDUCs, obviously, with reduced capital, that's going to impact that some. And as Al spoke later, I mean, we looked at this from a portfolio standpoint. And I think as we look at the iDUCs, we fully anticipate we will not get through the existing iDUCs that we have in '16, which really sets us up great for '17. So again, we'll talk a little bit more about it in the March call, but I think it's going to benefit '17. But no, we will not get through our complete iDUC inventory.

Evan Calio
Morgan Stanley, Research Division

Let me see if I could slip just one last one in here. I mean, you guys have correctly been more cautious on the commodity outlook since early 2015. I mean, and given your production resiliency and ability to do significantly more with less and similar trends in the U.S., are you preparing for a down cycle that can last well into 2017? Or can you share any of your macro outlooks, at least in regard to how you're setting up the company right now?

Robert G. Gwin
President

Well, if I can take a minute and I'll play Al and look through the looking glass, yes, we do think the current environment that we're in will probably be protracted. We have concerns of events here that really are well beyond our control. And consequently, until we see events stabilize and we see oil prices, in particular, take on new supply/demand dynamic than is currently in the market or anticipated in the near future, we will continue to be a very cautious investor in this environment. And you're right, you go back to this call a year ago, I think we were very concerned that this was going to be much longer in its recovery period and it tends to -- at that time, people tended to want to think it might be the case. We also go back to prior periods in history, when some of us that have been around in the oil and gas business a long time, typically, when you go into a down cycle, we've come out of a down cycle with a pretty good price increase. We are a little concerned that this time, there is one dynamic we've never had previously, and that is shale response in a short-cycle investment to a rising price environment has not been in the equation previously, and that will probably add to greater volatility in the coming years than we have certainly seen in the last 5, and I would even say, in the last 30. We've just not seen shale in its short-term inventory and its ability to respond to prices in the same way we do now. Now I'm not trying to paint a picture that looks like North American natural gas because here, we've got 94 million barrels a day of demand being maybe oversupplied 1.5 million to 2 million barrels a day. That's a very different environment than natural gas in North America, and so it could correct itself. But as prices move up and the intersection of supply and demand improves prices over time, it'll largely come from a supply contraction in the near term, not from a demand response. And I think all of us and I'd say, most importantly, most economists have been very surprised at the very limited demand response we've seen by the lower petroleum product prices around the world. So it's for those reasons that I think we're taking, again, this year and into '17 a very cautious approach.

Operator

Our next question is from Ed Westlake of Credit Suisse.

Edward George Westlake
Crédit Suisse AG, Research Division

These are probably two longer-term questions, just in the Gulf of Mexico, obviously Shenandoah. I think you still have one more well you want to drill there. People are still saying that we're waiting and seeing to see how low things like facilities costs can go. But I'd appreciate any update in terms of the prices you think would be required to get some the like Shenandoah or, say, a Yeti over the line.

R. A. Walker
Chairman & CEO

Let me take part of that. We're not -- today, we are not drilling with a view that we would develop Shenandoah in a $30-price environment. So I think you could probably frame the issues is that as we've appraised -- and Bob can -- is going to walk you through kind of where we see the next step on appraisal here, taking a final investment decision or sanctioning here is not something that will happen in 2016. And if price is -- when we do -- when we are looking at the commerciality of this particular development, it will be considered as a part of how we think about investing the capital in the development. So the 2 are very separate. So I think I'd like Bob to talk to you a little bit about what we're seeing from the appraisal perspective. But I think if you're concerned about us taking a sanctioning or final investment decision in a $30-price environment for Shenandoah, I can put that one to bed pretty quickly.

Robert G. Gwin
President

Yes, this is Bob. So we just finished the Shenandoah 4 appraisal wells located out to the west of our previous activities. We found over 620 feet of high-quality oil play in that well. We're very pleased with it. We also were able to get about 550 feet of core that's important for planning what that development could look like. So that's going to be analyzed, turned over to the reservoir engineers as they put together a scenario for how we might develop that. At the same time, we're looking at drilling Shenandoah 5. We think that's a well that's required. It's off to the East. It'd be kind of between Shenandoah 3 and the original Shenandoah 1, up dip of Shenandoah 3, which was a wet well that encountered very, very good sands, kind of gave us a down-dip limit on the eastern side. So that well should spud here in this first quarter. We have high expectations for it. But we need to drill the well and say, that's what appraisal is all about. Meanwhile, the guys are taking all the information that we obtained from this, rolling it into conceptual planning as to what resources we may be able to recover, how much it might cost, those types of things. And as Al said, we're a long ways from sanction at this point. If Shenandoah 5 is successful, we may move even farther to the east with the Shenandoah 6, but of course, that'll be all dependent on what happens to Shenandoah 5. Yeti, we're pretty much done at Yeti with the assessment of it. We drilled the initial well, had success there in Middle Miocene, good oil pay, good reservoirs. We went down-dip with the sidetrack and encountered the water, so that we got a good handle on where the oil-water contact would be. So we've got a fairly good limit on that side of it. We then drilled the Yeti 3 well, which was really an exploratory well with a down-dip tail to get some information on Yeti. But we didn't think it was going to be particularly good well from a hydrocarbon prospectivity in the original Yeti discovery. The upper zone that we were targeting had very good sands, but it was wet. But we were then able to go down to the Middle Miocene, get a core across that interval. So again, get the information that's needed for the teams to put together their development plans. This is going to be a very nice tieback into one of the existing nearby infrastructures. And so the folks are working on that, but again, they got a lot of work to do. And then the commodity prices have to cooperate, along with service costs, to make sure that, that's an economically viable project when we do decide to move forward with it.

Edward George Westlake
Crédit Suisse AG, Research Division

My second FID-related question is around Mozambique. I mean, it feels like you guys have been doing a lot of work and making a lot of progress. I mean, maybe just a run-through of what i's need to be crossed and t's dotted or the other way around to be ready to move forward with that project up to the markets.

R. A. Walker
Chairman & CEO

Well, I'm going to ask Mitch Ingram, if you wouldn't mind, to kind of make -- give you an overview of where we are. But I think similar comment that I made, pardon me, as it relates to Shenandoah would be appropriate for Mozambique. And that we've got a lot of things that we and our partners and the government need to work on. And with that, Mitch, why don't you, if you would, just give him a little bit of an overview.

Mitchell W. Ingram
Executive Vice President of International, Deepwater & Exploration

Okay. So we continue to make progress with this project. At the end of last year, we reached agreement with the government on a number of important issues to drive value certainty. And in 2016, we hope to conclude our negotiations with the government on the key agreements, better known as legal and contractual framework. And we hope to make further progress with the customers and financiers who underpin the project. I think, when this is done, FID will -- all 3 elements are combined, and these are linked, which will then provide us certainty to the project and allow us to realize significant value.

Operator

Our next question is from John Herrlin of Société Générale.

John Powell Herrlin
Societe Generale Cross Asset Research

Two quick ones. Al, you talked about innovative financing regarding the monetizations. Can you be more specific? What's innovative?

R. A. Walker
Chairman & CEO

Well, I think we've done some things in the past, John, that were a little bit different than others by the drill-to-earn things that we achieved, both onshore, initially in the Marcellus and later in the Eagle Ford, and then we took it into the Deepwater and then to Mozambique. One of the things I take a lot of comfort in as well as a lot of pride, that Bob Gwin and our financial organization do a lot of things, I think, that are leading edge. And I think we will find some innovative different ways to approach the land, which we look at funding our capital needs. And that's not to imply that we're going to get out ahead of things with stuff, but rather to be innovative. And I've always believed that one of the competing differences -- differentiators for Anadarko has been our ability to be ahead of the curve in finance. And Bob, you're welcome to weigh in with any comments you'd like in addition.

Robert G. Gwin
President

I don't have anything else.

John Powell Herrlin
Societe Generale Cross Asset Research

Okay, that's fine. And next one for me, you said, Al, that we're going to be in a world with greater product price volatility, shorter cycles, et cetera. Does this mean, going forward, that you may contemplate reducing the long-cycle business or perhaps taking more of a consortia approach going forward for things like deepwater plays?

R. A. Walker
Chairman & CEO

Well, I would say in the near term, John, our focus on tiebacks could be part of that answer. I think greenfield project development, unless we have a substantial estimated ultimate recovery from some of our exploration activities, do make it a little more challenging. One of the things I think we've done a good job of is we've developed various things as being able to fund the market to take the development component of our funding and development costs. Whether that market's always there will be a function of the economics. I think as we come out of this cycle, and we certainly, at some point, will, and to what extent we'll find out, I think in the near term, as we come out of the cycle, we will move back to a higher weighting in our short-cycle inventory and move the weighting that we've moved the last couple of years into intermediate and longer-cycle investing and ship that back to short. That, in part, will have something to do with what we believe would be attractive rates of return we can get from our short-cycle investing. So the 2 of those would be taken together, but the volatility is something, I think, we, as people who have to look at this every day, is going to be a lot different in the next 5 years, maybe 10 years than it certainly has been in the last 5 or 10 years.

Operator

Our next question is from Ryan Todd of Deutsche Bank.

Ryan M. Todd
Deutsche Bank AG, Research Division

Great. Maybe if I could ask one, can you talk a little bit about the utilization of your rigs over the next couple of years? You've got a number of rigs under contract. You're obviously still drilling on -- doing appraisal work in Shenandoah. Can you talk about how you might use the rigs in terms of appraisal versus exploration over the next 12 to 18 months.

James J. Kleckner
Former Executive Vice President of International and Deepwater Operations

Ryan, this is Jim. And our rigs -- the 5 we have under contract right now, one is in Côte d'Ivoire, running an exploration program. We anticipate that rig to stay in CI and then return back to Colombia to follow up on some exploration appraisal activity. The other 4 rigs are in the Gulf of Mexico, and they have various exploration date terms. And so what we'll do is utilize those rigs through contract on various appraisals and tieback opportunities that we talked about earlier. And some of those are, be Heidelberg field drill out that we've continued to see positive results in, and of course, had our early first production on; and then in K2 infill well opportunities, which are another example of short-cycle tieback opportunities like Caesar/Tonga. So we'll keep the rigs busy there as well as additional drilling in Lucius as we see expansion opportunities there and potentially Phase II expansion in Caesar/Tonga for additional reserve developments.

Ryan M. Todd
Deutsche Bank AG, Research Division

Great. And then maybe if I could ask one on the dividend. How do you think about the dividend and its place in your cash spend in a constrained capital environment?

Robert G. Gwin
President

This is Bob. I mean, the dividend is costing about $550 million a year currently. Obviously, there are other things we could do with that cash in the current environment yielding, say, 3% with the movement in the stock price. That's a bit higher than we would normally target for the dividend. So we've got a Board meeting next week. And obviously, the decisions around the dividend are solely theirs. We'll be talking to them about the overall financial picture and the cash flows during the year. And we'll see, as we come out of that, where we are relative to the appropriate level of dividend. I certainly do not expect us to eliminate the dividend. That's a question we've gotten in the past. I don't think that's an appropriate step. But the current yield is certainly higher than we would have targeted in a much higher stock price environment.

Operator

Our next question is from Charles Meade of Johnson Rice.

Charles Arthur Meade
Johnson Rice & Company, L.L.C., Research Division

I was wondering if you could perhaps, Bob, could gives us, say a narrative of what you've learned and seen in Colombia over the last -- with the Calasu well, over the last few months and, I think, what you saw with that well, I think with your modeling of the basin and perhaps if you learned anything on the geochemistry side.

Robert G. Gwin
President

Yes, Charles. This is Bob. I've talked about the Kronos well on our last call where we found 130 to 230 feet of gas bay that looked to be biodegraded thermogenic oil based on the geochemistry. Everything that we've done on the geochemical side is holding up with that type of an interpretation. The Kronos well was not as -- didn't have as well developed sands as maybe we would have hoped, although the objective section does look like it blooms out to the North in a much better area, and we'll be testing that this year. As you move 100 miles to the north of Calasu, we're moving closer to what we look at the depicenter [ph], which is the Magdalena fan system. We are very peripheral to it at Kronos, but in the Calasu, we're getting into a much more proximal portion of it. We saw excellent sand development at Calasu. We had about 17 meters of gas bay in one of the sands. We're working the geochemistry on it to see -- as we went deeper in the well, we seem to be getting evidence of heavier components, but we didn't have any significant accumulation of-- to speak of as we move further down. So -- and the temperature data seem to confirm our interpretation. As we move from Kronos up towards Calasu, the overall basin gets warmer, but it's still a very cool basin. So that -- it still speaks to the, most likely, generative bays being oil in the areas that we're looking. So we're encouraged about what we've seen. We've learned an awful lot. We're now stepping back and deciding what it means to us in the Grand Fuerte area. At the same time, we acquired

a big 3D up in the coal area last year, and we're doing Phase 2 this year. And what we're seeing up there is really exciting and is also -- given the ties that we have from the previous 2 wells, when we take that up into the coal area, it gets us very excited about the prospectively of the coal area. And so Colombia has got a lot more to do. We've got a lot of good data, and so we're rolling that in. We're over at Paon right now. We've got quite a bit of activity at Paon. It's going to take us into the second half of the year, but when we're done there, the rig will come back into Colombia and drill, what we call our purple angel well, which will be testing the Fuerte area, and probably the Kronos appraisal is really what it's targeted, but it got some exploratory components to it.

Charles Arthur Meade
Johnson Rice & Company, L.L.C., Research Division

Got it. And that would be late '16, it sounds like?

Robert G. Gwin
President

Yes, I think it's definitely second half of '16. It kind of depends on how good we do at Paon with the DSTs and that kind of activities.

Charles Arthur Meade
Johnson Rice & Company, L.L.C., Research Division

Got it. That adds a lot. I appreciate it. Al, if I could to go back, this is I think a couple of people tried to take a crack at this already, but I'd like to take one more shot. I was struck by some of the word choice in your quote in the press release specifically said, "In 2016, greater market dislocation appears likely," And can you elaborate on what that dislocation is? My first sense is to think is that you're talking about commodity prices, but as I looked at that as a second time, I thought maybe you could be talking about the dislocation between service costs and the commodity price or some other thing.

R. A. Walker
Chairman & CEO

Yes, I think it's more the latter to help you just a little bit there. I mean, if you go back and think about what it takes, I mean, we're not really in the revenue business. We're in the margin business. And so in this price environment, we have a dislocation between what it costs to either operate or drill wells versus other commodities that are being provided by the market. So that dislocation is -- we believe, is going to continue. We don't find the margins, that we're seeing today, to be attractive for the reasons I have talked about this morning. And I think indicative of how we've, over time, done things, our ability with a substantially reduced capital plan, 50%, down from last year's 70%, down from 2014, being able to maintain oil volumes flat year-over-year on a divestiture-adjusted basis speaks to the quality of a portfolio that has a good mix of conventional and unconventional resources to lean on. But that market dislocation certainly gives us a pause for doing more than the capital spending that we've talked about for the year.

Operator

Next question is from Scott Hanold of RBC.

Scott Michael Hanold
RBC Capital Markets, LLC, Research Division

If I could just maybe focus my questions on where do you think the market needs to be, to think about spending more capital? And one of the things you didn't highlight, but I noticed on your updated investor presentation is that the Wattenberg economics look pretty compelling. I mean, IDCs at $25 a barrel and new drills at $30 a barrel. But what price do you need to see in the market that's sustainable to start thinking about accelerating activity?

R. A. Walker
Chairman & CEO

Well, as I've tried as best I can, which may be isn't exactly to the question, we really can't answer that generically. And every asset today has different types of breakevens. Every types -- every asset has a little bit different characteristics. As you think about our DJ Basin position with the mineral interest underlying it there versus the Delaware Basin where we see ourselves in a very attractive yield stream associated with the hydrocarbons being produced there, we can't just pinpoint a number for you as easily as it probably sounds like we should be able to. I think if you think back to a year ago when we were at a much higher price and we were having hesitation then, we have seen our efficiencies improve. We've seen some costs continue to come down. I think you saw that most recently in the fourth quarter. And I think we'll continue to find improvements around efficiencies. And again, we're in the margin business. We're not in the revenue business. So it really is, when our margins return to a level that gives us a wellhead margin that creates an acceptable rate of return, asset-by-asset, that we'll see ourselves going back into our various portfolio opportunities with capital. Until then, we're going to stay in a value-preservation mode.

Phil Corbett
RBS Strategy

Okay. Understood. And you made a comment that, maintenance capital is about 2/3 of what it was last year. Could you provide some color and context around that? In addition, I think, in prior calls, you had mentioned your base declines around 18% or so. Where does that stand as you look into 2016?

R. A. Walker
Chairman & CEO

Well, we've done some work on this, and I'm going to ask John, if he could, just to give you a little bit of additional information. But a lot of this we anticipate -- well, we don't just anticipate, we will go into greater detail on March 1. But today, the number that we think there's a maintenance CapEx to keep volumes flat is about $1.8 billion, which is down substantially from prior years and I think very, very reflective of the outstanding work our employees have been able to achieve by reducing that breakeven.

John M. Colglazier
Investor Relations Professional

Yes, Scott. I think it kind of goes along with what we just talked about your comments for around Wattenberg. I mean, having those type of breakevens, having the flexibility we have there with the 120 IDCs that we've built up. Again, to Darrells' point, it doesn't appear we'll utilize them all this year. But all that contributes, and especially, taking into account what Jim Kleckner and his guys are doing in the Gulf of Mexico with the tiebacks. I don't have to sum up -- I'm not spending money this year to get Heidelberg. We've already spent most of the money to get the volumes from the TEN complex. Having a full year of Lucius that's outperforming expectations, all that blends in to a much lower capital requirement keep our volumes flat year-to-year. And to Al's comment in his opening remarks, we expect to be down on a divestiture-adjusted basis, plus or minus, 1% to 4%. So it kind of says even then that we're not spending even to the level to keep volumes flat. So I think having the flexibility to still focus on our longer-dated assets and keep the sustainability portion of the portfolio going, is a pretty special thing, and I'm pretty proud of what we've been able to do.

Operator

Our next question is from Bob Morris of Citi.

Robert S Morris
Citigroup Inc, Research Division

My question is already answered.

Operator

And the next question is from Paul Sankey of Wolfe.

Paul Benedict Sankey

Wolfe Research, LLC

I guess the big story of the quarter was the Apache story, which obviously had a big impact on your stock price. Could you just look back on that and address it again first? I assume that you feel that the market perception of what happened there was a bit erroneous. And I just wondered if, for the benefit hindsight, you could add any color.

R. A. Walker
Chairman & CEO

Paul, I think you can fully appreciate. I think we've said all we wanted to say and could say, in early November, in that press release. I think some of the market activity in our sector had to do a lot of factors, and we were certainly a part of that. But those were external and separate and apart from the event you're making reference to. So I know you're looking for additional comments from me, but I think we made all the comments we intend to make in that press release.

Paul Benedict Sankey
Wolfe Research, LLC

Understood. If we could totally change the subject. How do you think about hedging now? Would you be more likely to hedge at a lower price, higher than here, but at a lower level than you previously would have been? Or are you more likely to simply allow the price to rally and take what the market gives you?

Robert G. Gwin
President

Well, at $30 and $2, just to use big round numbers. I don't think any company has got a motivation to hedge in to what's probably a negative cost of replacement. So I'm not sure we or anybody else would find ourselves motivated to lock in prices that are lower than the marginal cost in order to develop.

Paul Benedict Sankey
Wolfe Research, LLC

Yes, I understand that. At this level, what I'm saying is, would you be more inclined to hedge, let's say, at 40 or 45, where previously we would have talked about 60?

Robert G. Gwin
President

It comes back to what kind of margin we get at the wellhead. If we are finding ourselves with an attractive wellhead margin that we want to be able to somewhat lock in for a short to intermediate period of time, that would be something that we would find worth spending some time on. Typically in the past, we've tried to approach every period. We're taking about half of the hydrocarbon price risk off the table, whether it's natural gas or oil. That philosophical view hasn't changed, but it really comes back to seeing something in the market that gives us that wellhead margin that's attractive to be able to use the derivatives to help us protect the price movements from.

Paul Benedict Sankey
Wolfe Research, LLC

Understood. And then finally for me, it's been put to me that the price of oil, as you mentioned, is so low right now that actually completing DUCs is not economic. Is that fair? And I'll leave it there.

Robert G. Gwin
President

I think in our case, what we see is, is it's really from a capital allocation perspective, the reason that Darrell is talking about the inventory of DUCs from the beginning of the year to the end of the year, is more reflective of our Heidelberg and 10 longer-term projects coming into production, coupled with the tieback opportunities that we see in the Gulf of Mexico actually having better rates of return. Again, that's

just the ability to have a conventional and unconventional mix of resources allows us not to have to lean on assets in an environment that only do well in a short-cycle environment.

Operator

Our next question is from Dave Heikkinen of Heikkinen Energy.

David Martin Heikkinen
Heikkinen Energy Advisors, LLC

Al and Bob, kind of curious about your discussions with your investment grade bondholders and how they see the rating agencies' potential moves impacting their ability to hold -- downgrade it or not investment-grade debt in their portfolios?

R. A. Walker
Chairman & CEO

You bet. Bob's much more capable of responding to your question than I am. I just wanted to say, thank you. I noticed this morning you upgraded us, and that's appreciated. Bob?

Robert G. Gwin
President

Thanks, Al. David, obviously, we talked to those bondholders. I'm not in a position to comment on things they might have said about their ability or willingness to continue to hold the bonds I think they need to -- those conversations are best held with the individuals. I will say that certain of them that I've spoken to are concerned about some of the approaches that Moody's, in particular, might take relative to their historic methodology conversations that they've held that caused them to believe that, perhaps, what traditionally were just subcomponents of Moody's methodology become overriding factors and that there's a political dynamic at work that is not necessarily linear relative to the last several years of an approach that we can all rely upon. And that certainly appears to be affecting bondholders comfort with the current situation. I don't believe that same dynamic exists with the views of how S&P is taking, what I would call, more of a traditional, measured response to the commodity price environment. But those are all anecdotal types of things. We don't know that they would come to pass, but they're the types of things that, quite frankly, I think our fixed income holders are concerned about and appropriately so. And then all we can really do in that type of an environment is manage as responsibly as we can, continue to do what we've done historically, focusing on the quality of the assets. The asset coverage, obviously, cash flows are impacting the current environment. And that is a temporary dislocation, even if it exists longer than a year. And we've tried to, and are continuing to manage the portfolio on what we believe is a long-term responsible basis to provide stability as an investment grade company to those fixed income investors that have relied upon the way that we have traditionally managed the business and the way the rating agencies have traditionally established their parameters.

R. A. Walker
Chairman & CEO

And David, as you can tell, Bob has no energy around that topic at all.

David Martin Heikkinen
Heikkinen Energy Advisors, LLC

Not at all. Now I've heard the same kind of institutional disruption particularly tied to Moody's. So that's a helpful perspective. And then I know this is a sensitive topic, but your focus on the margins and the current price that the markets' providing. I mean, how long, at this activity level, would you maintain current staffing levels? And how do you think about the cycle of building the company up and then where you are now versus kind of where your current G&A is?

R. A. Walker
Chairman & CEO

Well, I think you can probably appreciate, and what we believe is a protracted commodity environment, not only for this year but for the coming years. We, and I think, every other company in our industry will take this opportunity to look at the environment. Think up its capital plan, its activity, what its workforce needs, and I don't think we're going to be any different than anyone else as we go through this period of unfortunate, as I said earlier in a response to another question, market dislocation.

David Martin Heikkinen
Heikkinen Energy Advisors, LLC

Okay. And that's what I thought. And then just very detailed, I guess, what were the volumes to your -- add at Heidelberg and TEN? I just want to get the numbers that you're expecting.

R. A. Walker
Chairman & CEO

David, if you don't mind, I mean, we've got -- you're going to take away all the stuff we get to talk about in March if we answer your question. We will go into a lot of detail March 1.

Operator

Our next question is from Brian Singer, Goldman Sachs.

Brian Arthur Singer
Goldman Sachs Group Inc., Research Division

Wanted to ask on the minerals interests and your royalty interest and land grants. I wanted to see if there's any change to how you're thinking about that strategically, and your willingness to monetize that in any way in the context of creative monetization opportunities.

R. A. Walker
Chairman & CEO

Brian, it's Bob. No, no change to our messaging over the last couple of quarters. In this kind of a commodity price environment we actually have, I think, put out some numbers on what the royalty income looked like in this past year. It's obviously down pretty sharply year-over-year. It's highly correlated to prices. It's not the type of environment where we would seek to monetize the royalties around oil and gas. I will point out, though, that an exception to that rule is our hard minerals royalties. We own the largest natural Soda Ash reserves in the world, and we have a fairly nice income stream around those assets that give -- where we have some flexibility. And its -- and that market, in particular, in contrast to our fossil fuel commodity prices, that market looks pretty good in today's environment.

R. A. Walker
Chairman & CEO

Yes. I'll just say, in response to that question, I guess, John Herrlin answered earlier, I do think Bob Gwin and Al Richey have worked in a very innovative way in their approach in how they may -- maybe monetizing those assets in the near future.

Brian Arthur Singer
Goldman Sachs Group Inc., Research Division

Great. And then just wanted to ask a follow-up question on the drill and complete inventory. You mentioned you may not complete all of that this year. Can you be a little more specific on what you do expect to complete this year as part of the $2.8 billion budget?

Robert G. Gwin
President

If I can, and I know Darrell would love to answer your question, but if we answer your question, and I'm going to back to what I said to Dave, we are not going to have anything to talk about on March 1. I think the other thing is that you have to appreciate, that's all rolled into the capital plan which we're going to

recommend to our board. And until we have that plan approved by our board, to get out in front of them will be sort of inappropriate.

Operator

Our next question is from Jeffrey Campbell from Tuohy Brothers.

Jeffrey Leon Campbell
Tuohy Brothers Investment Research, Inc.

First question I wanted to ask is, will you have any potential take-or-pay issues within the Wattenberg in 2016? We recently saw a deal where an operator transferred pipeline obligations from the Wattenberg to the Delaware Basin. And some of the DJ pipeline operators have been hurt by declining volumes.

A. Scott Moore
Former Senior Vice President of Midstream & Marketing

Jerry, this is Scott Moore with Marketing. So we maintain a flexible portfolio out at the DJ between our own pipeline commitments, and we feel comfortable on our ability to keeping them fully utilized.

Jeffrey Leon Campbell
Tuohy Brothers Investment Research, Inc.

Okay, great. You mentioned in the ops report some confidence that the Delaware basin recoverable oil estimates will increase over time. I'm just wondering, this may be a March 1 rejection, but can you add some color on when are these could take place to realize your expectations?

R. A. Walker
Chairman & CEO

Okay, we'll let Darrell answer that one.

Darrell E. Hollek
Former Executive Vice President of Operations

No, we addressed this last quarter, but then as we continue to do look-backs, we'll touch on this again March 1, but as we continue to do look-backs, our EORs continue to climb and so we're getting a lot of confidence that not only over a small area, but the greater 230 million acres or 1,000 acres that the EURs are only climbing. So we still have a lot of work to do as we go into the next year, in terms of looking at all the different horizons, not only the Wolfcamp A and B, but Bone Springs 2 and 3. But at this point, we're nothing but encouraged.

Jeffrey Leon Campbell
Tuohy Brothers Investment Research, Inc.

So if I tried to paraphrase it briefly, it sounds like the core is expanding.

Darrell E. Hollek
Former Executive Vice President of Operations

Yes, it is. I think that would be a fair assessment.

Operator

Our next question is from Harry Mateer of Barclay's.

Harry Mead Mateer
Barclays Bank PLC, Research Division

I guess, first, just returning to the credit ratings questions earlier. I know this concern about the agency methodologies, which you guys don't control, but you're not only bystanders at the same time. So I guess, what I'm looking for is what are you prepared to do to protect those ratings? Are you prepared to raise

capital if that's what the agencies need to see? Where do your investment-grade ratings stand on that priority scale for you?

R. A. Walker
Chairman & CEO

What was the end of the question, Harry? Where do the what?

Eliot Casper Javanmardi
Capital One Securities, Inc., Research Division

Where do the ratings sit on that priority scale for you overall?

Robert G. Gwin
President

Yes. The ratings are a very high priority for us. I mean, we've said on several occasions that maintaining investment-grade ratings are important to us and very central to the way we want to operate our business model as an international exploration company, as a company that is leading a project, selling LNG volumes are on the world, et cetera. So it's very important to us. Certainly, we've got a lot of flexibility before we -- in our opinion, before we would need to raise capital in order to address concerns. I think one of the issues is that are the concerns reasonable? And are they addressable by simple knobs that one could turn? We talked about the dividend earlier. We've talked about asset sales. We mentioned north of $1 billion in the near term that would more than fund, in addition to our discretionary cash flow, would more than fund the $2.8 billion budget. We've got a list of assets beyond that, that we're actively working and would expect to be able to execute during 2016. Things that are what Al talked about, our net debt staying flat or reducing the big variable and reducing leverage there is execution against the asset sales. And if for some reason, we needed to continue to reduce net debt, and weren't able to execute on asset sales, then you continue to work down your list of items that become a little more distasteful the further down the list you go, but are the types of things that we would have to consider whether or not to pursue, relative to where the rating agencies, where the ratings from all 3 agencies are and whether steps are defined by those agencies that they'd like to see if, indeed, they take actions. So it is -- you're right, we're far more than bystanders. We're actively engaged in addressing this all very proactively. But we also want to make sure that we're doing things that are responsible relative to the true underlying risk and not -- and that true underlying risk isn't always captured in a particular agency's view of an action that they may take at a point in time. So we're just trying to take it all in balance and be responsible and iterative in our approach.

R. A. Walker
Chairman & CEO

I've answered this question, as well as Bob, in a lot of other settings. And I think the variables that we have that are most controllable for the management teams here are: reducing our capital plan, which, as of today, you can see our motivation there by reducing our capital plan year-over-year, 50%, 70% lower than it was in 2014; also looking at continuing to do asset sales and monetizations, which we have a long and very successful track record of doing. And as the question was asked earlier, and I think Bob appropriately replied, is we look at the yield associated with our common stock at 3%, that's historically high for us. So we look forward to discussing that with our Board. And I believe those are the most important variables in the near term that we can address.

Eliot Casper Javanmardi
Capital One Securities, Inc., Research Division

And then, I guess, on the upcoming maturity, you mentioned your plans to refinance it. But it looks like you're planning to spend or seeking approval to spend more than the $1.8 billion you indicated as maintenance capital. So I guess my question is, why not pull back on spending even more and then use asset sale proceeds or other sources of cash to pay down that maturity and actually delever instead of just looking to refinance it?

R. A. Walker
Chairman & CEO

Well, there's a lot of things that we'll go into March 1 that probably today will feel a little hollow in terms of my response, just because I'm not prepared today to go into detail around things we've not -- sought Board approval for. And I think it's just appropriate that we wait and have that conversation with our Board first. But our business is -- as we see it today, philosophically, is about preservation. And we do think there are things that we can invest in, in the intermediate long cycle that, in fact, do just that. But I think at $2.8 billion or the $1.8 billion maintenance number, our ability in this environment to hold oil volumes flat year-over-year on a divestiture-adjusted basis, and our only decline in actual volume coming from gas properties, that we're not investing in, is a pretty good indication of what we feel like is the way in which we want to manage through a very difficult and challenging period, and yet have it be capital-responsive to the environment that the hydrocarbon prices are giving us. If you allow ourselves to continue to go completely into hibernation, and things come out at some point from this cycle and you're not prepared to then take advantage of what you can do, then we've somewhat allowed ourselves to not maximize our equity return for the cost associated with the credit profile. And I think Bob addressed it beautifully, exactly what we feel like we want to do in order to maintain the highest credit quality as possible, at the same time, not stall out our equity story.

Operator

This includes our question-and-answer session. I'd like to turn the conference back over to Al Walker for any closing remarks.

R. A. Walker
Chairman & CEO

Well, thank you. And I think today, you saw as evidence that our management team is committed to a much lower capital spend than, I think practically any one anticipated. I think also, you've heard from us today, we'll go into greater detail on March 1 about how we get to that $1.8 billion maintenance CapEx. I've talked repeatedly about our -- what we believe is a very attractive year-over-year sales volume that we're able to achieve, and the only declines coming from natural gas properties that we're not investing in. I also made a comment or 2, and I'll just highlight it again. We have extremely good line of sight today for monetizations in excess of $1 billion, which we hope to be announcing between here and our March 1 conference call. We think that would, and should, address a lot of the concerns and questions that have been posed to us about how we intend to fund our activities in 2016. And I think, one of the things that has probably been lost in the scheme of just exactly who we are and what we are, but I've tried -- I think almost every call to emphasize it, we are a mix of conventional and unconventional resources. And in 2016, you're seeing the benefit of conventional assets coming into the production profile. And that's a very different opportunity set than a lot of other companies have. I think that nice cocktail of mix between conventional and unconventional continue to resonate. I think you'll see it in the way in which our performance plays out through the year. And I do think, and I know a lot of companies talk about this, I'll say it again, we have an exceptional culture with great employees and a tremendous track record of achieving what we established for the year is what we think we can achieve, and want to achieve, and typically go beyond that. So I don't think 2016 will be any different than that. It's definitely going to be a tough year. But the opportunities we have, I think, are quite significant. And I also think the way in which we manage our capital, we manage our business, and we have a culture that can succeed in any environment will be quite important as we get through this year and in the years to come after this. So I appreciate the support we've seen from a lot of investors through this very difficult period. Those of you that have hung in there with us, we greatly appreciate it. Those of you that are new to the investment, we look forward to making sure that everybody feels that we're doing everything we possibly can. And with that, operator, we'll call it a day, and look forward to talking to everybody on March 1. Thank you.

Operator
The conference has now concluded. Thank you for attending today's presentation. You may now disconnect.

Exhibit 102

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2015

or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from   to

Commission File No. 1-8968

ANADARKO PETROLEUM CORPORATION
(Exact name of registrant as specified in its charter)

Delaware	**76-0146568**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1201 Lake Robbins Drive, The Woodlands, Texas	**77380-1046**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code **(832) 636-1000**

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, par value $0.10 per share	New York Stock Exchange
7.50% Tangible Equity Units	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer," and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☒

The aggregate market value of the Company's common stock held by non-affiliates of the registrant on June 30, 2015, was $39.6 billion based on the closing price as reported on the New York Stock Exchange.

The number of shares outstanding of the Company's common stock at February 5, 2016, is shown below:

Title of Class	Number of Shares Outstanding
Common Stock, par value $0.10 per share	508,438,647

Documents Incorporated By Reference

Portions of the Definitive Proxy Statement for the Annual Meeting of Stockholders of Anadarko Petroleum Corporation to be held May 10, 2016 (to be filed with the Securities and Exchange Commission prior to March 31, 2016), are incorporated by reference into Part III of this Form 10-K.

TABLE OF CONTENTS

PART I

Items 1 and 2. Business and Properties

GENERAL

Anadarko Petroleum Corporation is among the world's largest independent exploration and production companies, with approximately 2.1 billion barrels of oil equivalent (BOE) of proved reserves at December 31, 2015. Anadarko's mission is to deliver a competitive and sustainable rate of return to shareholders by developing, acquiring, and exploring for oil and natural-gas resources vital to the world's health and welfare. Anadarko's asset portfolio is aimed at delivering long-term value to stakeholders by combining a large inventory of development opportunities in the U.S. onshore with high-potential worldwide offshore exploration and development activities.

Anadarko's asset portfolio includes U.S. onshore resource plays in the Rocky Mountains, the southern United States, the Appalachian basin, and Alaska. The Company is also among the largest independent producers in the deepwater Gulf of Mexico and has exploration and production activities worldwide, including activities in Algeria, Ghana, Mozambique, Colombia, Côte d'Ivoire, New Zealand, Kenya, and other countries.

Anadarko is committed to producing energy in a manner that protects the environment and public health. Anadarko's focus is to deliver resources to the world while upholding the Company's core values of integrity and trust, servant leadership, people and passion, commercial focus, and open communication in all business activities.

Anadarko's business segments are separately managed due to distinct operational differences and unique technology, distribution, and marketing requirements. The Company's three reporting segments are as follows:

Oil and gas exploration and production—This segment explores for and produces oil, condensate, natural gas, and natural gas liquids (NGLs) and plans for the development and operation of the Company's liquefied natural gas (LNG) project in Mozambique.

Midstream—This segment engages in gathering, processing, treating, and transporting Anadarko and third-party oil, natural-gas, and NGLs production. The Company owns and operates gathering, processing, treating, and transportation systems in the United States for oil, natural gas, and NGLs.

Marketing—This segment sells much of Anadarko's oil, natural-gas, and NGLs production as well as third-party purchased volumes. The Company actively markets oil, natural gas, and NGLs in the United States; oil and NGLs internationally; and the anticipated LNG production from Mozambique.

Unless the context otherwise requires, the terms "Anadarko" or "Company" refer to Anadarko Petroleum Corporation and its consolidated subsidiaries. This Annual Report on Form 10-K and the documents incorporated herein by reference contain forward-looking statements based on expectations, estimates, and projections as of the date of this filing. These statements by their nature are subject to risks, uncertainties, and assumptions and are influenced by various factors. As a consequence, actual results may differ materially from those expressed in the forward-looking statements. See *Risk Factors* under Item 1A of this Form 10-K.

Available Information The Company's corporate headquarters is located at 1201 Lake Robbins Drive, The Woodlands, Texas 77380-1046, and its telephone number is (832) 636-1000. The Company files or furnishes Annual Reports on Form 10-K; Quarterly Reports on Form 10-Q; Current Reports on Form 8-K; registration statements, or any amendments thereto; and other reports and filings with the U.S. Securities and Exchange Commission (SEC). Anadarko provides access free of charge to all of these SEC filings, as soon as reasonably practicable after filing or furnishing, on its website located at www.investors.anadarko.com/sec-filings. The Company will also make available to any stockholder, without charge, printed copies of its Annual Report on Form 10-K as filed with the SEC. For copies of this Form 10-K, or any other filing, please contact Anadarko Petroleum Corporation, Investor Relations, P.O. Box 1330, Houston, Texas 77251-1330, call (855) 820-6605, send an email to investor@anadarko.com, or complete an information request on the Company's website at www.anadarko.com by selecting Investors/Shareholder Resources/Shareholder Services.

The public may read and copy any materials Anadarko files with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, DC 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC maintains a website at www.sec.gov that contains reports, proxy and information statements, and other information regarding issuers, including Anadarko, that file electronically with the SEC.

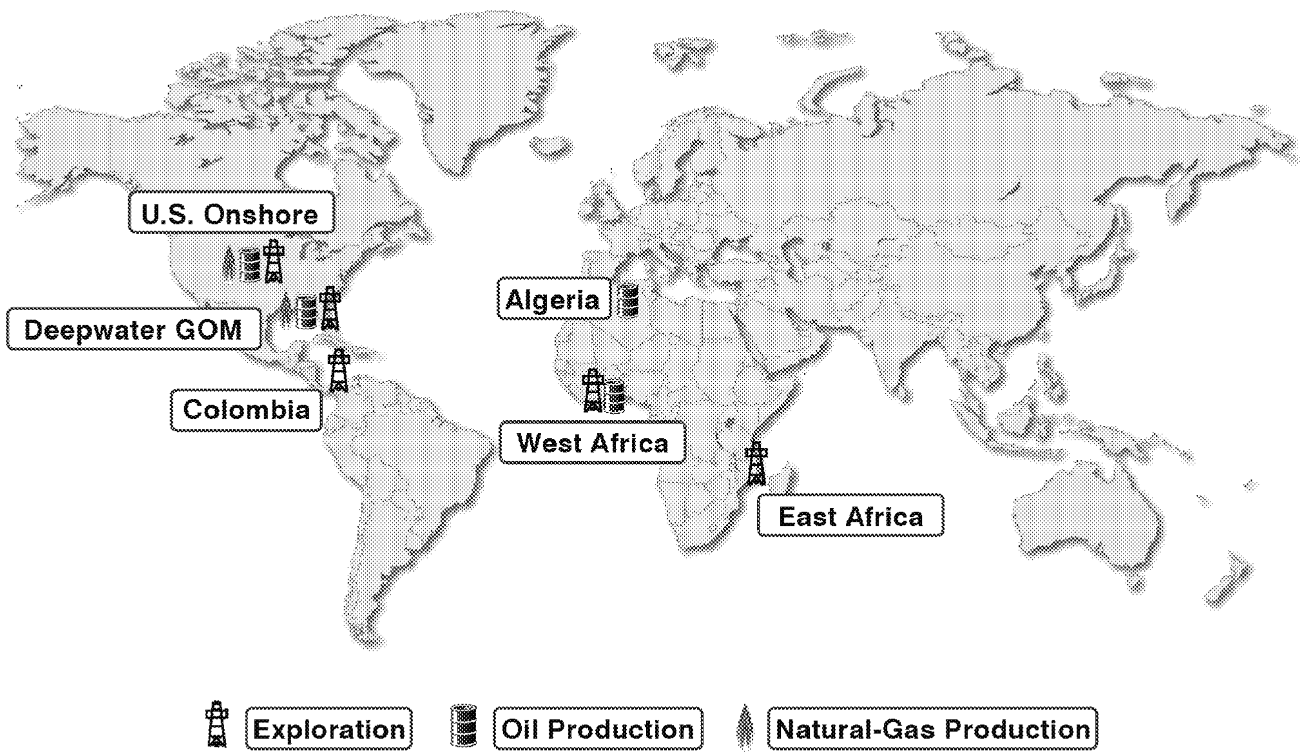
Operating Outlook During 2015, the oil and natural-gas industry experienced a significant decrease in commodity prices driven by a global supply/demand imbalance for oil and an oversupply of natural gas in the United States. The decline in commodity prices and global economic conditions have continued into 2016, and low commodity prices may exist for an extended period.

The Company plans to continue its disciplined and focused approach in 2016 by emphasizing value over growth, enhancing operational efficiencies, reducing capital expenses, and managing its diverse asset portfolio. Management has recommended to the Board of Directors (Board) a 2016 capital budget of approximately $2.8 billion, which excludes the capital budget of Western Gas Partners, LP (WES), a publicly traded consolidated subsidiary. The $2.8 billion budget is nearly 50% lower than capital investments in 2015 and almost 70% lower than 2014.

The Company will continue to evaluate the oil and natural-gas price environments and may adjust its capital spending plans to maintain the appropriate liquidity and financial flexibility. Anadarko expects that its capital expenditures will be aligned with its cash flows from operations and targeted asset monetizations.

OIL AND GAS PROPERTIES AND ACTIVITIES

The map below illustrates the locations of Anadarko's significant oil and natural-gas exploration and production operations:

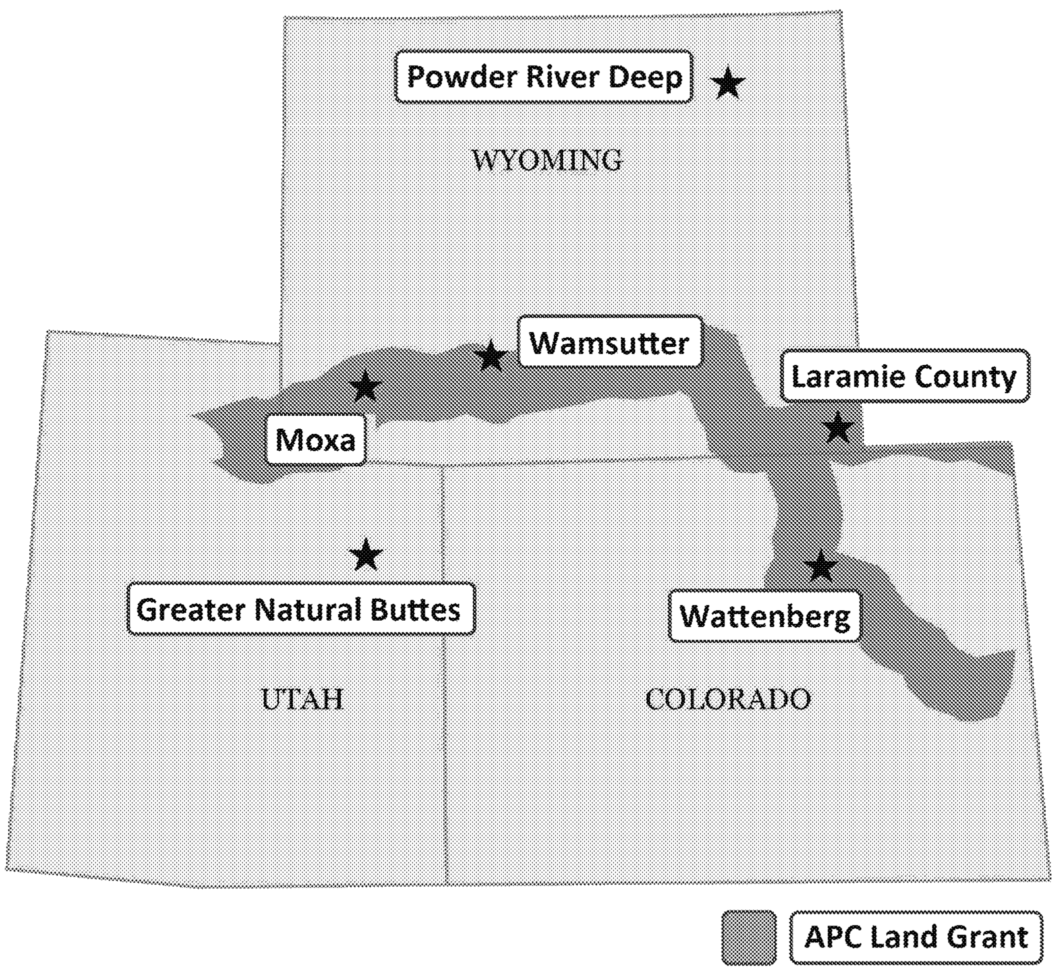


United States

Overview Anadarko's U.S. operations include oil and natural-gas exploration and production in the onshore Lower 48 states, deepwater Gulf of Mexico, and onshore Alaska. The Company's U.S. operations accounted for 89% of sales volumes and 80% of sales revenues during 2015, and 90% of proved reserves at year-end 2015.

Rocky Mountains Region Anadarko's Rocky Mountains Region (Rockies) properties include oil and natural-gas plays located in Colorado, Utah, and Wyoming, where the Company operates approximately 11,000 wells and owns interests in approximately 4,000 nonoperated wells. Anadarko operates fractured-carbonate/shale reservoirs and tight-gas assets within the region. The Company also has fee ownership of mineral rights under approximately eight million acres that pass through Colorado and Wyoming and into Utah (known as the Land Grant). Management considers the Land Grant a significant competitive advantage for Anadarko as it enhances the Company's economic returns from production, offers drilling opportunities for the Company without expiration, and allows the Company to capture royalty revenue from third-party activity on Land Grant acreage. The Company also believes its liquids-rich reservoirs, strong well performance, low development and operating costs, and large expandable midstream infrastructure each provide tangible benefits to the Company.

In 2015, activities in the Rockies primarily focused on production and adding reserves through horizontal drilling, infill drilling, and optimizing both wellbore and completion design. In addition, a major emphasis was placed on reducing capital and operating expenses and increasing efficiencies to enhance margins. In 2015, Rockies liquids sales volumes increased by 11% over 2014, equivalent to 17 thousand barrels of oil equivalent per day (MBOE/d), even with a reduction in sales volumes of 21 MBOE/d related to the impact of ethane rejection. The Company drilled 447 wells and completed 390 wells in the Rockies during 2015, primarily in the Wattenberg field, which is expected to be a focus area for Anadarko in 2016.



Wattenberg Anadarko operates approximately 5,000 vertical wells and 1,000 horizontal wells in the Wattenberg field. The field contains the Niobrara and Codell formations, which are naturally fractured formations that hold both liquids and natural gas. During 2015, the Company's drilling program focused entirely on horizontal development, drilling 365 horizontal wells. Sales volumes in the field increased 32% compared to 2014, with increases of 29% in oil volumes and 27% in total liquids volumes. Horizontal drilling results in the field continue to be strong, with economics that are enhanced by the Company's ownership of the Land Grant mineral interest, a consolidated core acreage position, and recent enhancements to the operated and controlled infrastructure and takeaway capacity.

Drilling spud-to-rig-release cycle time improved from 10.5 days in 2014 to 6.3 days in 2015. The full-year 2015 average drilling cost per foot was reduced by approximately 40% and completion capital was reduced by 32% relative to 2014. Operated well capital costs in 2015 have decreased to less than $3.5 million from $4.0 million in 2014 for an equivalent well, driven by continued operational efficiencies and supply-chain savings. During 2015, Anadarko intentionally deferred completions in order to focus on preserving value by decreasing capital investments in a lower commodity-price environment and to provide additional production flexibility for 2016.

In 2015, the second cryogenic processing train at the Lancaster plant was placed into service, resulting in an additional 300 million cubic feet per day (MMcf/d) of processing capacity and a field-wide increase in NGLs recoveries. The Company made substantial progress toward completion of its centralized oil stabilization facility (COSF) in 2015 and expects to commission the facility in early 2016. The COSF will increase oil recoveries, enhance efficiencies of tank batteries, lower operating expenses, and further reduce impacts on the environment. Anadarko added 180 MMcf/d of field compression in 2015, which reduced gathering system pressures in the field, enhancing system efficiency and improving the base production profile.

Greater Natural Buttes The Greater Natural Buttes area in eastern Utah is one of the Company's major tight-gas assets. The Company uses cryogenic processing facilities in this area to extract NGLs from the natural-gas stream. The Company operates approximately 2,900 wells in the area and drilled 60 wells in 2015. Average drilling cost per foot was reduced by 10% and completion capital was reduced by 23% relative to 2014. The Company operated the field at a reduced activity level for the majority of 2015 due to capital being diverted to higher-margin projects.

Powder River Deep The Company drilled a three-well exploration/appraisal program targeting the Turner formation, where the Company has previously seen strong results. Additionally, a farm-out agreement was reached during the first quarter of 2015, whereby Anadarko may be carried in at least three deep horizontal tests to further evaluate multiple oil objectives. The farm-in party has the option to earn up to 40,000 net acres of Anadarko's position. The Company controls over 325,000 acres of deep mineral rights within the Powder River basin.

Laramie County Anadarko holds ownership in more than 100,000 mineral-interest acres in this emerging liquids-rich play in the northern DJ basin in Wyoming. In 2015, the Company participated in more than 70 nonoperated wells testing the Niobrara and Codell formations. Results from 33 producing wells, 11 with first production in 2015, remain strong, with initial 30-day net production averaging approximately 1,000 barrels of oil equivalent per day (BOE/d).

Greater Green River Basin Anadarko operates over 1,400 wells in the Wamsutter and Moxa fields. The Company also carries a nonoperated position in 2,600 wells across the two fields. Much of this producing area is located within the Land Grant, which enhances the Company's economics in projects in the area. Anadarko reached a farm-out agreement in July 2015, whereby the Company will be fully carried on several exploration wells testing a liquids-rich opportunity located on the Land Grant.

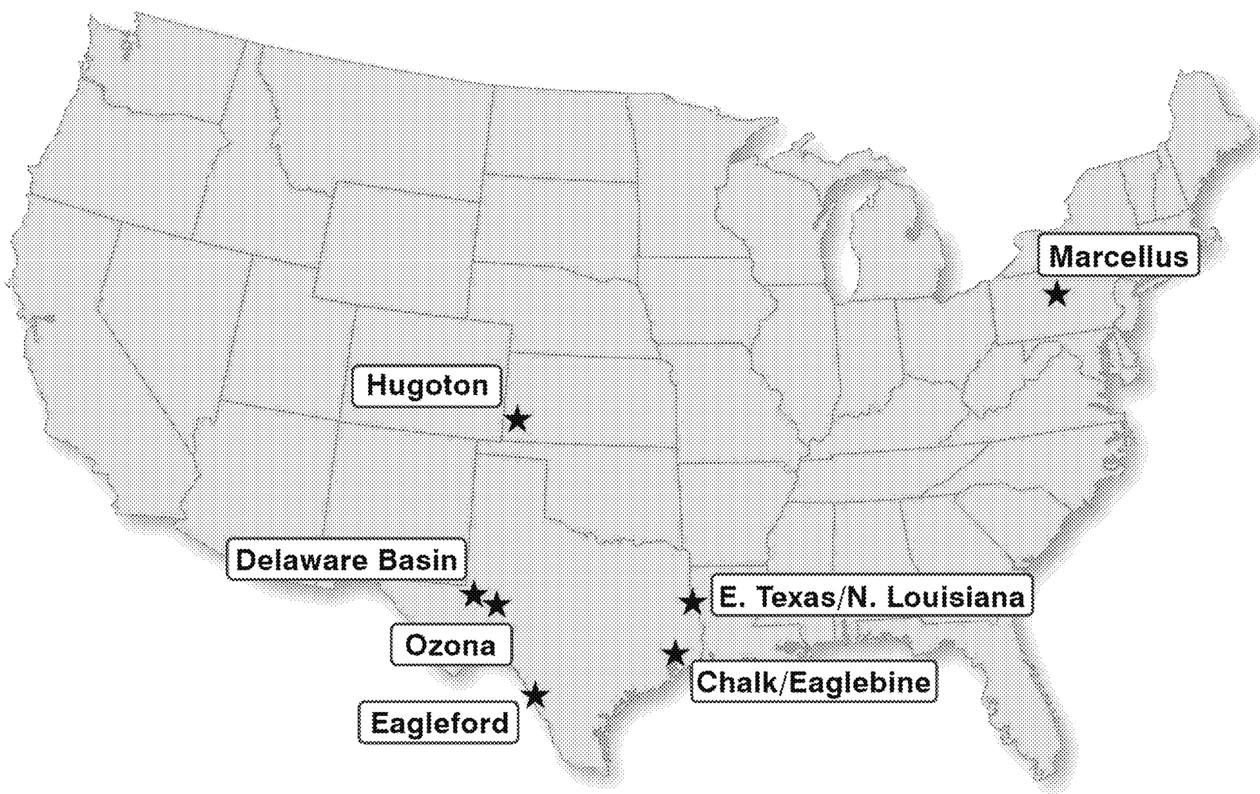
Coalbed Methane Properties During 2015, Anadarko sold its interest in its Powder River basin coalbed methane wells and related midstream assets for net proceeds of $154 million after closing adjustments.

Salt Creek and Monell During 2015, Anadarko sold its interest in the Salt Creek and Monell enhanced oil recovery assets in Wyoming, with a sales price of $703 million, for net proceeds of $675 million after closing adjustments.

Southern and Appalachia Region Anadarko's Southern and Appalachia Region properties are primarily located in Texas, Pennsylvania, Louisiana, and Kansas. The region includes the Eagleford shale in South Texas, the Delaware basin in West Texas, the Marcellus shale in north-central Pennsylvania, and the Haynesville shale in East Texas and Northern Louisiana. Operations in these areas are focused on finding and developing both natural gas and liquids from shales, tight sands, and fractured-reservoir plays.

During 2015, the Company continued to focus on improving its cost structure, delivering efficient production, and delineating its position in the Delaware basin. Activities in the region targeted continued drilling, completion and operational efficiencies, and process improvements and optimization, providing both lower costs and cycle-time improvements across the region. Compared with the prior year, capital expenditures were reduced in the region as the Company focused on higher-margin areas within the U.S. onshore to support future growth. Additional production flexibility for 2016 was provided by infrastructure expansions primarily in the Delaware basin, reductions in completion costs across the region, and the systematic buildup of intentionally deferred completions in the Eagleford shale and Delaware basin.

In 2015, liquids sales volumes in the region increased by 10%, although a decrease in gas sales volumes resulted in a total sales volume decrease of 5% from 2014. The Company drilled 338 operated horizontal wells and brought 318 wells online in 2015. In July 2015, Anadarko sold its interest in the Bossier natural-gas field and associated midstream assets in East Texas, with a sales price of $440 million, for net proceeds of $425 million after closing adjustments. In 2016, the Company expects to continue its horizontal drilling program, focusing on the Delaware basin.



Delaware Basin Anadarko holds interests in over 600,000 gross acres in the Delaware basin. Anadarko's 2015 drilling activity primarily targeted the Wolfcamp shale play, liquids-rich Bone Spring 2 tight sands, and the Avalon shale play. In 2015, Anadarko drilled 80 operated wells and participated in 49 nonoperated wells. Significant infrastructure continues to be added to facilitate future growth from this asset. At year-end 2015, the Company had six operated rigs drilling in the Wolfcamp shale.

The successful Wolfcamp shale delineation program continues to deliver encouraging results across the majority of Anadarko's acreage position. Anadarko is testing multiple zones within the Wolfcamp shale and several development concepts for increased efficiency, including multi-well pads, extended laterals, and horizontal-well spacing. The Company has identified thousands of potential drilling locations in the Wolfcamp formation that are expected to provide substantial opportunity for Anadarko's future activity in the basin.

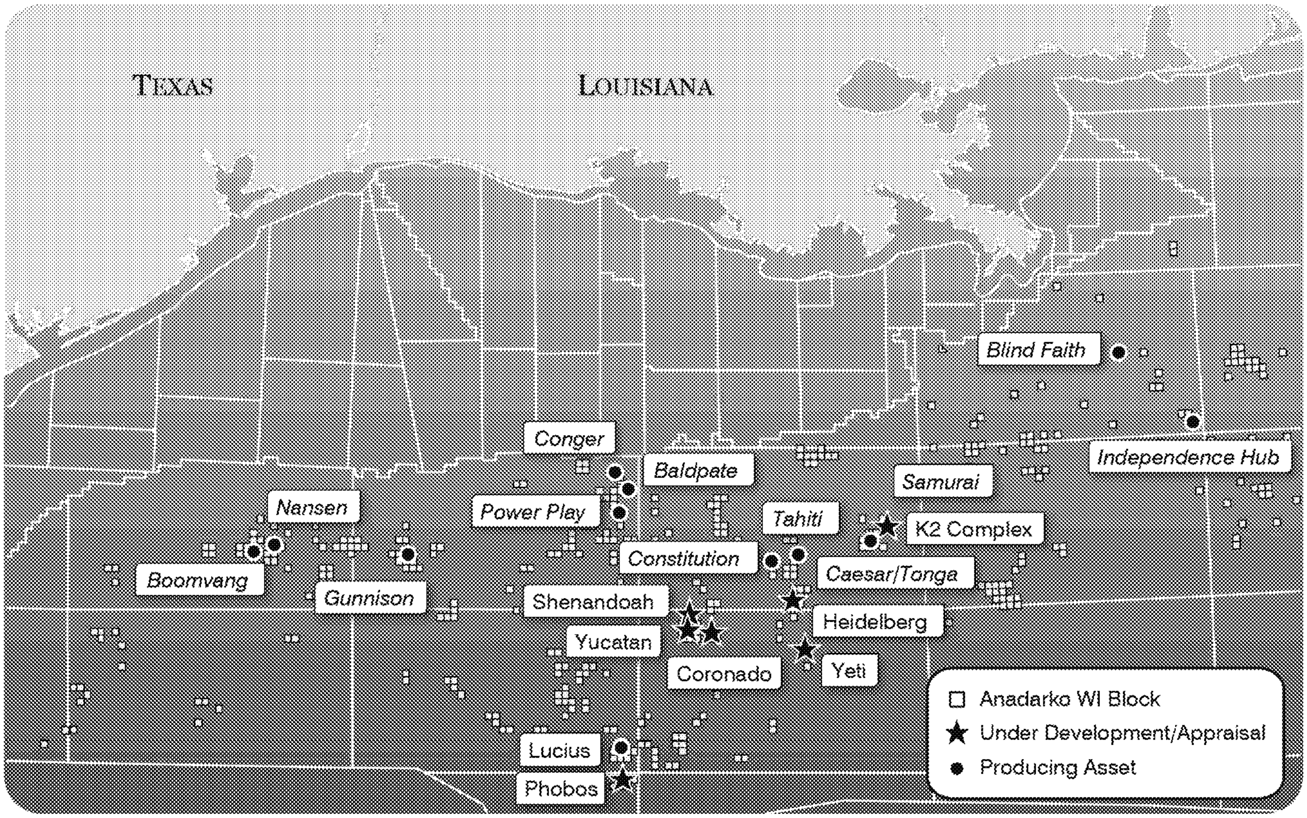
Eagleford The Eagleford shale development in South Texas consists of approximately 346,000 gross acres and over 1,300 producing wells. In 2015, the Company averaged 4 drilling rigs, drilled 183 wells, completed 179 wells, and brought 201 wells online, generating sales volume growth of 20% over 2014. In 2015, Anadarko continued to recognize improvements in Eagleford shale drilling efficiency, translating to record-low average cost per foot, while increasing average lateral length. Anadarko completed five successful tests targeting the mid and upper Eagleford shale zones and intends to test for additional reserves across its acreage position. The Company also continued to optimize other development parameters such as completions design, spacing, and choke management.

Eaglebine Anadarko holds 156,000 gross acres in the Eaglebine shale in Southeast Texas, most of which is held by existing Austin Chalk production. In 2015, Anadarko continued to delineate and develop this acreage by drilling 24 operated horizontal wells with a one-rig program. Under a carried-interest arrangement entered into in 2014, which requires a third party to fund $442 million of Anadarko's capital costs in exchange for a 34% working interest in the Eaglebine development, Anadarko has generated positive cash flow in an unfavorable commodity-price environment while testing new concepts and opportunities. At December 31, 2015, $111 million of the total $442 million carry obligation had been funded.

East Texas/North Louisiana Anadarko holds 223,000 gross acres in East Texas/North Louisiana. Anadarko continued its capital program in the East Texas/North Louisiana area in 2015, targeting the liquids-rich Haynesville shale in East Texas and the prolific dry-gas Haynesville shale in North Louisiana. In 2015, Anadarko averaged 3.5 operated rigs and drilled 39 wells in the Haynesville and Cotton Valley formations.

Marcellus The Company holds 625,000 gross acres in the Marcellus shale of the Appalachian basin. In 2015, 1 operated horizontal well was drilled and Anadarko participated in the drilling of 18 nonoperated horizontal wells. The Company's sales volumes in the Marcellus shale decreased in 2015 as the Company reduced its investment and production in the area in response to the lower commodity-price environment and ongoing third-party pipeline infrastructure maintenance.

Gulf of Mexico Anadarko owns an average working interest of 60% in 279 blocks in the Gulf of Mexico. The Company operates eight active floating platforms and holds interests in 34 fields. During 2015, the Company advanced development of the Lucius and Heidelberg projects and continued an active deepwater development and appraisal program in the Gulf of Mexico as it continues to take advantage of existing infrastructure to cost-effectively develop known resources.



Development

Lucius The Company realized first production at the Anadarko-operated Lucius Spar in January 2015, bringing on six wells throughout the early part of 2015. The Lucius project was developed with production startup only three years from sanction and five years from discovery. The 80-thousand barrels per day (MBbls/d) spar is located in Keathley Canyon Block 875 at a water depth of 7,000 feet. The Company has realized steady production performance at nameplate capacity since May 2015. Anadarko entered into a carried-interest arrangement with a third party in 2012. The $476 million carry commitment was fully funded in 2014 and covered a substantial majority of Anadarko's capital costs through first production. Following the carried-interest arrangement and 2014 equity re-determination, the Company holds a 23.8% working interest in Lucius.

Heidelberg During 2015, the Company continued to advance the Anadarko-operated Heidelberg development project, which was sanctioned during the second quarter of 2013. Installation of the Lucius-lookalike spar was completed and first oil was realized in January 2016, three months ahead of schedule. Three wells are ready for production and are expected to be brought online during the first quarter of 2016, while an additional two wells are expected to be drilled later in 2016.

In 2013, the Company entered into a carried-interest arrangement requiring a third party to fund $860 million of capital costs in exchange for a 12.75% working interest in the project. At December 31, 2015, $793 million of the $860 million carry obligation had been funded. Anadarko holds a 31.5% working interest in Heidelberg.

Caesar/Tonga At Caesar/Tonga (33.75% working interest), the Company successfully completed a fifth development well (GC 683#2) in the first quarter of 2015. Anadarko has recently completed a sixth development well (GC 683#3), which is expected to come online later in the first quarter of 2016. A seventh well (GC 726#2) reached total depth in January 2016 and encountered over 250 net feet of oil pay. The well is currently being completed. Due to the continued success at Caesar/Tonga, the Company sanctioned a Phase 2 development plan during the fourth quarter of 2015 and anticipates first oil in the fourth quarter of 2017.

Constitution At Constitution (100% working interest), the Company executed a successful platform drilling program in 2015, where the A4 well was sidetracked, completed, and brought online.

K2 Complex At K2 (41.8% working interest), the GC 562#5 infill well, which found 210 net feet of oil pay in the Miocene, was successfully completed. The GC 561#3 development well found 331 net feet of oil pay in the M9, M10, and M15 sands and is currently being completed. First production is anticipated by the second quarter of 2016.

Independence Hub Gas Complex The last producing well at Independence Hub (IHUB) watered out in December 2015. IHUB was a tremendous asset for the Company with cumulative gross production of 1.3 trillion cubic feet of natural gas in eight and a half years. Plans to plug and abandon the remaining IHUB wellbores and decommission the facilities are underway.

Exploration

Two nonoperated exploration wells were drilled in the Gulf of Mexico during 2015. The Yeti exploration well (37.5% working interest) targeted a sub-salt Miocene-aged three-way closure in Walker Ridge and encountered more than 270 net feet of oil pay. The Yeti discovery is located in approximately 5,900 feet of water, approximately 20 miles south of Anadarko's operated Heidelberg field. The Thorvald exploration well (50% working interest), located in approximately 4,800 feet of water in southern Mississippi Canyon, tested multiple sub-salt Miocene reservoirs in a three-way closure and encountered approximately 80 net feet of oil pay.

Appraisal

Shenandoah The Company spud the Shenandoah-4 well, the third appraisal well at the Shenandoah discovery (30% working interest), in the second quarter of 2015. The well tested the up-dip extent of the basin. The subsequent Shenandoah-4 sidetrack encountered more than 620 net feet of oil pay, extending the lowest known oil column down-dip. Following the success of the Shenandoah-4 sidetrack, the Company and its partners successfully acquired more than 550 feet of whole-core from the hydrocarbon-bearing reservoir interval.

Yeti The Yeti discovery well was successfully sidetracked to test the down-dip limits of the field. The Yeti-3 appraisal well finished drilling during the fourth quarter of 2015 and was successful in acquiring more than 320 feet of whole-core across the primary Miocene-aged reservoir intervals encountered in the Yeti discovery well. The Company and its partners are currently evaluating potential development options for the Yeti discovery.

Alaska Anadarko's nonoperated oil production and development activity in Alaska is concentrated on the North Slope. Infrastructure construction began in 2013 on the Alpine West satellite development, a 15- to 33-well extension of the Alpine field. Drilling at Alpine West commenced in 2015, with four out of seven producing wells coming online during the fourth quarter of 2015 at a combined rate of 20 MBbls/d.

The Greater Mooses Tooth 1 (GMT1) project was sanctioned in November 2015 and will become the next satellite development west of the Alpine field. First production at GMT1 is expected in 2018.

International

Overview Anadarko's international operations include oil, natural-gas, and NGLs production and development in Algeria and Ghana, along with activities in Mozambique where the Company continues to make progress towards a final investment decision on an LNG development. The Company also has exploration acreage in Colombia, Côte d'Ivoire, Mozambique, New Zealand, Kenya, and other countries. International locations accounted for 11% of Anadarko's sales volumes and 20% of sales revenues during 2015, and 10% of proved reserves at year-end 2015. In 2016, the Company expects to focus its exploration and appraisal activity in Côte d'Ivoire and Colombia.

Algeria Anadarko is engaged in production and development operations in Algeria's Sahara Desert in Blocks 404 and 208, which are governed by a Production Sharing Agreement between Anadarko, two other parties, and Sonatrach, the national oil and gas company of Algeria. The Company is responsible for 24.5% of the development and production costs for these blocks. The Company produces oil through the Hassi Berkine South and Ourhoud central processing facilities (CPF) in Block 404 and oil, condensate, and NGLs through the El Merk CPF in Block 208. Gross production through these facilities averaged more than 368 MBbls/d in 2015, and the cumulative gross production from all three facilities reached a significant milestone, surpassing 2.0 billion BOE in July 2015. The Company drilled seven development wells in 2015.

Ghana Anadarko's production and development activities in Ghana are located offshore in the West Cape Three Points Block and the Deepwater Tano Block.

The Jubilee field (27% nonoperated unit interest), which spans both the West Cape Three Points Block and the Deepwater Tano Block, averaged gross production of 103 MBbls/d of oil in 2015. Natural-gas exports commenced in the fourth quarter of 2014, and in 2015, an average of 66 MMcf/d was exported from the Jubilee field to an onshore gas processing plant in satisfaction of a commitment established in conjunction with the Jubilee development plan. In 2015, development continued with the J-24 well completed as an oil producer; the J-37 well drilled, completed, and put on production; and the J-36 well drilled with completion planned for 2016. Following the appraisal work completed in 2014, the Mahogany and Teak fields were declared commercial in March 2015, and a full-field development plan for the Greater Jubilee Area was submitted to the government of Ghana in December 2015. At this time, options to further increase the oil and gas throughput capacity of the floating production, storage, and offloading vessel (FPSO) are under evaluation.

The Tweneboa/Enyenra/Ntomme (TEN) project (19% nonoperated working interest) is located in the Deepwater Tano Block. Significant progress was made during 2015, including completing mechanical work on the FPSO, drilling the eleventh well, and completing four of the wells in preparation for first oil. The TEN project will use an 80-MBbls/d-capacity FPSO for production from subsea wells. The project, which commenced in 2013, was more than 80% complete at year-end 2015 and remains on budget and on schedule for first production in the third quarter of 2016.

Mozambique Anadarko operates Offshore Area 1 (26.5% working interest), which totals approximately 1.2 million gross acres. The Company is progressing three elements that will position the project for execution and deliver future value: the legal and contractual framework to develop LNG in Mozambique; project finance; and long-term LNG sales contracts.

Development During the first half of 2015, the Company successfully executed a six-well drilling campaign in the Golfinho-Atum field. Following this campaign, an independent third party completed a resource certification for sufficient volumes from Golfinho-Atum to support the initial development of two LNG trains. Anadarko continues to work with the construction and installation contractors for opportunities to reduce execution risk once the project progresses to the construction phase. Anadarko and its partners continue to progress over eight million metric tonnes per annum of LNG offtake to long-term sales contracts. The July 2015 ratification of the Decree Law that was published by the Mozambique government in 2014 was a significant milestone in the establishment of a project-wide legal and contractual framework. During the fourth quarter of 2015, Anadarko and its partners executed a Unitization and Unit Operating Agreement with Offshore Area 4 partners that covers the joint development of the straddling Prosperidade (Offshore Area 1) and Mamba (Offshore Area 4) reservoir. The agreement is subject to government approval.

Exploration In Offshore Area 1, the Company completed drilling and evaluation operations at the Tubarão Tigre-2 appraisal well during the first quarter of 2015. The well successfully appraised the Tubarão Tigre discovery that was drilled in 2014.

In Onshore Rovuma (35.7% working interest), the Company completed drilling and evaluation operations at the Kifaru-1 well during the first quarter of 2015. The well did not encounter hydrocarbons and was plugged and abandoned.

Colombia Anadarko controls the exclusive rights to explore or conduct technical evaluation activities on nine blocks totaling approximately 16 million gross acres. The COL 1, COL 2, COL 6, and COL 7 blocks are operated at a 100% working interest and the remaining blocks are operated at a 50% working interest.

During 2015, Anadarko spud two exploration wells. The Kronos-1 (50% working interest) discovery encountered 130 to 230 net feet of natural-gas pay in the upper objective, proving the presence of a working petroleum system and validating the geologic and seismic interpretations. The well finished drilling during the third quarter of 2015 after testing a deeper objective where it encountered non-commercial hydrocarbons. Anadarko and its partner are evaluating the drilling results to determine the next steps. The Calasu-1 well (50% working interest) tested a large four-way structure located approximately 100 miles north of the Company's Kronos discovery. The well finished drilling during the fourth quarter of 2015 and encountered non-commercial quantities of pay.

Côte d'Ivoire Anadarko owns an operated working interest in four offshore blocks totaling approximately 1.0 million gross acres, including CI-103 with a 65% working interest and CI-527, CI-528, and CI-529, each with a 90% working interest. During the third quarter of 2015, Anadarko acquired the CI-527 block, which is contiguous with the CI-103 block to the northwest and the CI-528 block to the south. Planning is underway for a two-well exploration program on the CI-527 and CI-528 blocks in 2016.

A drilling and interference testing program began during the first quarter of 2016 as part of the continued appraisal of the Paon discovery (CI-103). The program will also include additional appraisal drilling. The data from these operations are expected to provide insight on reservoir connectivity, deliverability, fluid properties, and reservoir size.

New Zealand Anadarko controls the exclusive rights to explore or conduct technical evaluation activities on four blocks totaling approximately 42 million gross acres, of which 6.1 million gross acres are owned under exploration licenses. Anadarko owns an operated 45% working interest in the Canterbury basin block and an operated 100% working interest in two Pegasus basin blocks. In the 36 million acre New Caledonia basin block, Anadarko has a 25% nonoperated working interest. During 2015, the Company acquired a 3D seismic survey in the Canterbury basin and is currently evaluating potential future exploration opportunities.

Kenya Anadarko owns an operated 45% working interest in three offshore deepwater blocks, encompassing approximately 3.7 million gross acres. The Company is evaluating potential future exploration opportunities.

Other Anadarko holds exploration interests in approximately 300,000 gross acres in two offshore blocks located in the Campos basin of Brazil. Anadarko also has exploration opportunities in other overseas, new-venture areas, including Tunisia and South Africa.

Proved Reserves

Estimates of proved reserves volumes owned at year end, net of third-party royalty interests, are presented in billions of cubic feet (Bcf) at a pressure base of 14.73 pounds per square inch for natural gas and in millions of barrels (MMBbls) for oil, condensate, and NGLs. Total volumes are presented in millions of barrels of oil equivalent (MMBOE). For this computation, one barrel is the equivalent of 6,000 cubic feet of natural gas. Shrinkage associated with NGLs has been deducted from the natural-gas reserves volumes. Proved reserves are estimated based on the average beginning-of-month prices during the 12-month period for the respective year.

Disclosures by geographic area include the United States and International. For 2015, the International geographic area consisted of proved reserves located in Algeria and Ghana, which by country and in total represented less than 15% of the Company's total proved reserves. The Company sold its Chinese subsidiary in 2014.

Summary of Proved Reserves

	Oil and Condensate (MMBbls)	Natural Gas (Bcf)	NGLs (MMBbls)	Total (MMBOE)
December 31, 2015				
Proved				
Developed				
United States	**332**	**5,184**	**257**	**1,453**
International	**159**	**30**	**15**	**179**
Undeveloped				
United States	**193**	**807**	**68**	**396**
International	**29**	**—**	**—**	**29**
Total proved	**713**	**6,021**	**340**	**2,057**
December 31, 2014				
Proved				
Developed				
United States	352	6,635	304	1,762
International	190	27	13	207
Undeveloped				
United States	352	2,033	162	853
International	35	4	—	36
Total proved	929	8,699	479	2,858
December 31, 2013				
Proved				
Developed				
United States	347	7,120	268	1,801
International	202	—	—	202
Undeveloped				
United States	245	2,085	127	720
International	57	—	12	69
Total proved	851	9,205	407	2,792

The Company's proved reserves product mix increased to 52% liquids in 2015, compared to 49% in 2014 and 45% in 2013. The Company's year-end 2015 proved reserves product mix was 35% oil and condensate, 48% natural gas, and 17% NGLs.

Changes to the Company's proved reserves during 2015 are summarized in the table below:

MMBOE	**2015**	2014	2013
Proved Reserves			
January 1	**2,858**	2,792	2,560
Reserves additions and revisions			
Discoveries and extensions	**29**	63	145
Infill-drilling additions [(1)]	**89**	577	410
Drilling-related reserves additions and revisions	**118**	640	555
Other non-price-related revisions [(1)]	**289**	(137)	(40)
Net organic reserves additions	**407**	503	515
Acquisition of proved reserves in place	**1**	—	36
Price-related revisions [(1)]	**(624)**	(1)	(23)
Total reserves additions and revisions	**(216)**	502	528
Sales in place	**(279)**	(124)	(12)
Production	**(306)**	(312)	(284)
December 31	**2,057**	2,858	2,792
Proved Developed Reserves			
January 1	**1,969**	2,003	1,883
December 31	**1,632**	1,969	2,003

(1) Combined and reported as revisions of prior estimates in the Company's *Supplemental Information on Oil and Gas Exploration and Production Activities* (*Supplemental Information)* under Item 8 of this Form 10-K. Reserves related to infill-drilling additions are treated as positive revisions. Price-related revisions reflect the impact of current prices on the reserves balance at the beginning of 2015. Other non-price-related revisions are primarily a reflection of performance improvements coupled with the benefit of reduced year-end costs.

Proved reserves are estimated based on the average beginning-of-month prices during the 12-month period for the respective year. The average prices used to compute proved reserves at December 31, 2015, were $50.28 per barrel (Bbl) for oil, $2.59 per million British thermal units for gas, and $19.47 per Bbl for NGLs. Prices for oil, natural gas, and NGLs can fluctuate widely. If commodity prices remain below the average prices used to estimate 2015 proved reserves, the Company would expect additional negative price-related reserves revisions in 2016, which could be significant.

The Company's estimates of proved developed reserves, proved undeveloped reserves (PUDs), and total proved reserves at December 31, 2015, 2014, and 2013, and changes in proved reserves during the last three years are presented in the *Supplemental Information* under Item 8 of this Form 10-K. Also presented in the *Supplemental Information* are the Company's estimates of future net cash flows and discounted future net cash flows from proved reserves. See *Critical Accounting Estimates* under Item 7 of this Form 10-K for additional information on the Company's proved reserves.

The Company has not yet filed information with a federal authority or agency with respect to its estimated total proved reserves at December 31, 2015. Annually, Anadarko reports gross proved reserves for U.S.-operated properties to the U.S. Department of Energy. These reported reserves are derived from the same database used to estimate and report proved reserves in this Form 10-K.

Changes in PUDs Changes to PUDs during 2015 are summarized in the table below. Revisions of prior estimates reflect Anadarko's ongoing evaluation of its asset portfolio and include updates to prior PUDs, the addition of new PUDs associated with current development plans, the transfer of PUDs to unproved categories due to development plan changes, and the impact of changes in economic conditions, including changes in commodity prices. The Company's year-end development plans and associated PUDs are consistent with SEC guidelines for PUD development within five years unless specific circumstances warrant a longer development time horizon.

MMBOE	
PUDs at January 1, 2015	**889**
Revisions of prior estimates	**(199)**
Extensions, discoveries, and other additions	**12**
Conversions to developed	**(236)**
Sales	**(41)**
PUDs at December 31, 2015	**425**

Revisions In 2015, PUD reserves were revised downward by 199 MMBOE. Negative revisions of 419 MMBOE were due to the decline in commodity prices and include a reduction to NGLs reserves of 22 MMBOE associated with price-induced ethane rejection. The negative price-related revisions were partially offset by a net increase of 220 MMBOE driven by increases from improved economics associated with performance improvements coupled with reduced year-end costs, increases from successful infill drilling mainly in the Wattenberg area of the Rockies, and decreases primarily associated with updates to development plans to align with the current economic environment.

Extensions, Discoveries, and Other Additions During 2015, Anadarko added 12 MMBOE of PUDs through the extension of proved acreage, primarily as a result of successful drilling in the Wolfcamp shale play in the Southern and Appalachia Region.

Conversions In 2015, the Company converted 236 MMBOE of PUD reserves to developed status, equating to 36% of total year-end 2014 PUDs when adjusted for revisions and sales. Approximately 81% of PUD conversions occurred in U.S. onshore assets, 17% occurred in Gulf of Mexico assets, and the remaining 2% occurred in international assets.

In 2015, onshore development activity in the U.S. resulted in the conversion of 126 MMBOE in the Rockies, 61 MMBOE in the Southern and Appalachia Region, and 5 MMBOE in Alaska. An additional 40 MMBOE were converted in various Gulf of Mexico fields. The remaining PUD conversions in 2015 were associated with ongoing development of international assets.

Anadarko spent $2.4 billion to develop PUDs in 2015, of which approximately 75% related to U.S. onshore assets, 13% related to international assets, and 12% related to Gulf of Mexico assets.

Sales In 2015, PUD reserves decreased by 41 MMBOE due to asset sales, primarily associated with the Company's divestiture activities in the Rockies.

Development Plans The Company annually reviews all PUDs to ensure an appropriate plan for development exists. Typically, U.S. onshore PUDs are converted to developed reserves within five years of the initial proved reserves booking, but projects associated with arctic development, deepwater development, and international programs may take longer.

At December 31, 2015, the Company had 10 MMBOE of pre-2011 PUDs that remained undeveloped. Approximately two-thirds of these PUDs are associated with Gulf of Mexico opportunities that have been drilled and are scheduled for completion in 2016. The remaining pre-2011 PUDs are associated with the El Merk development project and are being developed according to an Algerian government-approved plan. Anadarko and its partners achieved initial oil production in 2013, and the El Merk facility reached maximum allowable oil production rates in 2014 when all of the fields were brought online and the facility became fully operational.

Technologies Used in Proved Reserves Estimation The Company's 2015 proved reserves additions were based on estimates generated through the integration of relevant geological, engineering, and production data, using technologies that have been demonstrated in the field to yield repeatable and consistent results as defined in the SEC regulations. Data used in these integrated assessments included information obtained directly from the subsurface through wellbores such as well logs, reservoir core samples, fluid samples, static and dynamic pressure information, production test data, and surveillance and performance information. The data used also included subsurface information obtained through indirect measurements such as seismic data. The tools used to interpret the data included proprietary and commercially available seismic processing software and commercially available reservoir modeling and simulation software. Reservoir parameters from analogous reservoirs were used to increase the quality of and confidence in the reserves estimates when available. The method or combination of methods used to estimate the reserves of each reservoir was based on the unique circumstances of each reservoir and the dataset available at the time of the estimate.

Internal Controls over Reserves Estimation Anadarko's estimates of proved reserves and associated future net cash flows were made solely by the Company's engineers and are the responsibility of management. The Company requires that reserves estimates be made by qualified reserves estimators (QREs) as defined by the Society of Petroleum Engineers' standards. The QREs are assigned to specific assets within the Company's regions. The QREs interact with engineering, land, and geoscience personnel to obtain the necessary data for projecting future production, net cash flows, and ultimate recoverable reserves. Management within each region approves the QREs' reserves estimates. All QREs receive ongoing education on the fundamentals of SEC definitions and reserves reporting through the Company's reserves manual and internal training programs administered by the Corporate Reserves Group (CRG).

The CRG ensures confidence in the Company's reserves estimates by maintaining internal policies for estimating and recording reserves in compliance with applicable SEC definitions and guidance. Compliance with the SEC reserves guidelines is the primary responsibility of Anadarko's CRG.

The CRG is managed through the Company's finance department, which is separate from its operating regions, and is responsible for overseeing internal reserves reviews and approving the Company's reserves estimates. The Director—Reserves Administration and the Corporate Reserves Manager manage the CRG and report to the VP—Corporate Planning. The VP—Corporate Planning reports to the Company's Executive Vice President, Finance and Chief Financial Officer, who in turn reports to the Chairman, President, and Chief Executive Officer. The Governance and Risk Committee of the Company's Board meets with management, members of the CRG, and the Company's independent petroleum consultants, Miller and Lents, Ltd. (M&L), to discuss the results of procedures and methods reviews as discussed below as well as other matters and policies related to reserves.

The Company's principal engineer, who is primarily responsible for overseeing the preparation of proved reserves estimates, has over 29 years of experience in the oil and gas industry, including over 15 years as either a reserves estimator or manager. His further professional qualifications include a degree in petroleum engineering, extensive internal and external reserves training, and asset evaluation and management. The principal engineer is a member of the Society of Petroleum Evaluation Engineers and the Society of Petroleum Engineers, where he has been a member for over 29 years. In addition, he is an active participant in industry reserves seminars and professional industry groups.

Third-Party Procedures and Methods Reviews M&L reviewed the procedures and methods used by Anadarko's staff in preparing the Company's estimates of proved reserves and future net cash flows at December 31, 2015. The purpose of the review was to determine if the procedures and methods used by Anadarko to estimate its proved reserves are effective and in accordance with the definitions contained in SEC regulations. The procedures and methods reviews by M&L were limited reviews of Anadarko's procedures and methods and do not constitute a complete review, audit, independent estimate, or confirmation of the reasonableness of Anadarko's estimates of proved reserves and future net cash flows.

The reviews covered 14 fields that included major assets in the United States and Africa and encompassed approximately 86% of the Company's estimates of proved reserves and associated future net cash flows at December 31, 2015. In each review, Anadarko's technical staff presented M&L with an overview of the data, methods, and assumptions used in estimating its reserves. The data presented included pertinent seismic information, geologic maps, well logs, production tests, material balance calculations, reservoir simulation models, well performance data, operating procedures, and relevant economic criteria.

Management's intent in retaining M&L to review its procedures and methods is to provide objective third-party input on the Company's procedures and methods and to gather industry information applicable to reserves estimation and reporting processes.

Sales Volumes, Prices, and Production Costs

The following provides the Company's annual sales volumes, average sales prices, and average production costs per BOE for each of the last three years:

	Sales Volumes				Average Sales Prices (1)			
	Oil and Condensate (MMBbls)	Natural Gas (Bcf)	NGLs (MMBbls)	Barrels of Oil Equivalent (MMBOE)	Oil and Condensate (Per Bbl)	Natural Gas (Per Mcf)	NGLs (Per Bbl)	Average Production Costs (2) (Per BOE)
2015								
United States								
Greater Natural Buttes	**1**	**126**	**4**	**26**	**$ 38.23**	**$ 2.00**	**$ 14.84**	**$ 10.70**
Wattenberg	**35**	**176**	**16**	**81**	**44.88**	**2.31**	**15.65**	**7.64**
Other United States	**49**	**550**	**25**	**165**	**45.19**	**2.45**	**18.33**	**8.51**
Total United States	**85**	**852**	**45**	**272**	**45.00**	**2.36**	**17.03**	**8.45**
International	**31**	**—**	**2**	**33**	**51.68**	**—**	**29.85**	**7.22**
Total	**116**	**852**	**47**	**305**	**46.79**	**2.36**	**17.61**	**8.31**
2014								
United States								
Greater Natural Buttes	1	154	4	31	$ 81.74	$ 3.93	$ 39.16	$ 10.30
Wattenberg	27	125	13	62	87.76	4.19	36.46	7.55
Other United States	46	666	26	182	88.29	4.08	34.29	9.07
Total United States	74	945	43	275	87.99	4.07	35.48	8.87
International	32	—	1	33	99.79	—	56.16	8.22
Total	106	945	44	308	91.58	4.07	36.01	8.80
2013								
United States								
Greater Natural Buttes	1	168	4	33	$ 87.46	$ 3.12	$ 41.79	$ 9.59
Wattenberg	16	102	6	40	94.27	3.75	41.75	7.92
Other United States	41	698	23	179	98.38	3.56	36.14	8.64
Total United States	58	968	33	252	97.02	3.50	37.97	8.65
International	33	—	—	33	109.15	—	—	9.96
Total	91	968	33	285	101.41	3.50	37.97	8.80

Mcf—thousand cubic feet
Bbl—barrel
(1) Excludes the impact of commodity derivatives.
(2) Excludes ad valorem and severance taxes.

Production costs are costs to operate and maintain the Company's wells, related equipment, and supporting facilities, including the cost of labor, well service and repair, location maintenance, power and fuel, gathering, processing, transportation, other taxes, and production-related general and administrative costs. Additional information on volumes, prices, and production costs is contained in *Financial Results* under Item 7 of this Form 10-K. Additional detail regarding production costs is contained in the *Supplemental Information* under Item 8 of this Form 10-K. Information on major customers is contained in *Note 22—Segment Information* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Delivery Commitments

The Company sells oil and natural gas under a variety of contractual agreements, some of which specify the delivery of fixed and determinable quantities. At December 31, 2015, Anadarko was contractually committed to deliver approximately 1,067 Bcf of natural gas to various customers in the United States through 2031. These contracts have various expiration dates, with approximately 33% of the Company's current commitment to be delivered in 2016 and 79% by 2020. At December 31, 2015, Anadarko also was contractually committed to deliver approximately 12 MMBbls of oil to ports in Algeria and Ghana through 2016. The Company expects to fulfill these delivery commitments with existing proved developed and proved undeveloped reserves.

Properties and Leases

The following shows the developed lease, undeveloped lease, and fee mineral acres in which Anadarko held interests at December 31, 2015:

	Developed Lease		Undeveloped Lease		Fee Mineral		Total	
thousands of acres	Gross	Net	Gross	Net	Gross	Net	Gross	Net
United States								
Onshore	4,451	2,947	3,482	1,472	10,235	8,529	18,168	12,948
Offshore	270	132	1,362	866	—	—	1,632	998
Total United States	4,721	3,079	4,844	2,338	10,235	8,529	19,800	13,946
International	499	113	46,691	34,259	—	—	47,190	34,372
Total	5,220	3,192	51,535	36,597	10,235	8,529	66,990	48,318

At December 31, 2015, the Company had approximately four million net undeveloped lease acres scheduled to expire by December 31, 2016, if the Company does not establish production or take any other action to extend the terms. The Company plans to continue the terms of many of these licenses and concession areas through operational or administrative actions and does not expect a significant portion of the Company's net acreage position to expire before such actions occur.

Drilling Program

The Company's 2015 drilling program focused on proven and emerging liquids-rich basins in the United States (onshore and deepwater Gulf of Mexico) and various international locations. Exploration activity in 2015 consisted of 28 gross completed wells, which included 22 U.S. onshore wells, 5 international wells, and 1 Gulf of Mexico well. Development activity in 2015 consisted of 902 gross completed wells, which included 892 U.S. onshore wells, 8 international wells, and 2 Gulf of Mexico wells.

Drilling Statistics

The following shows the number of oil and gas wells that completed drilling in each of the last three years:

	Net Exploratory			Net Development			
	Productive	Dry Holes	Total	Productive	Dry Holes	Total	Total
2015							
United States	**16.0**	**—**	**16.0**	**573.1**	**13.8**	**586.9**	**602.9**
International	**2.4**	**0.4**	**2.8**	**1.8**	**—**	**1.8**	**4.6**
Total	**18.4**	**0.4**	**18.8**	**574.9**	**13.8**	**588.7**	**607.5**
2014							
United States	35.6	1.6	37.2	811.4	6.0	817.4	854.6
International	0.9	4.5	5.4	—	—	—	5.4
Total	36.5	6.1	42.6	811.4	6.0	817.4	860.0
2013							
United States	62.9	1.4	64.3	879.3	3.3	882.6	946.9
International	0.2	3.5	3.7	5.4	—	5.4	9.1
Total	63.1	4.9	68.0	884.7	3.3	888.0	956.0

The following shows the number of wells in the process of drilling or in active completion stages and the number of wells suspended or waiting on completion at December 31, 2015:

	Wells in the process of drilling or in active completion		Wells suspended or waiting on completion [(1)]	
	Exploration	Development	Exploration	Development
United States				
Gross	2	24	63	848
Net	0.7	12.6	26.1	548.3
International				
Gross	—	—	62	29
Net	—	—	18.5	6.2
Total				
Gross	2	24	125	877
Net	0.7	12.6	44.6	554.5

(1) Wells suspended or waiting on completion include exploration and development wells where drilling has occurred, but the wells are awaiting the completion of hydraulic fracturing or other completion activities or the resumption of drilling in the future.

Productive Wells

At December 31, 2015, the Company's ownership interest in productive wells was as follows:

	Oil Wells [1]	Gas Wells [1]
United States		
Gross	3,898	20,518
Net	2,489.4	14,765.5
International		
Gross	195	7
Net	34.5	1.7
Total		
Gross	4,093	20,525
Net	2,523.9	14,767.2

(1) Includes wells containing multiple completions as follows:

Gross	217	2,703
Net	189.2	2,290.0

MIDSTREAM PROPERTIES AND ACTIVITIES

Anadarko invests in and operates midstream (gathering, processing, treating, and transportation) assets to complement its operations in regions where the Company has oil and natural-gas production. Through ownership and operation of these facilities, the Company improves its ability to manage costs, controls the timing of bringing on new production, and enhances the value received for gathering, processing, treating, and transporting the Company's production. Anadarko's midstream business also provides services to third-party customers, including major and independent producers. Anadarko generates revenues from its midstream activities through a variety of contract structures, including fixed-fee, percent-of-proceeds, and keep-whole agreements. Anadarko's midstream activities include WES, a publicly traded consolidated subsidiary and limited partnership that acquires, owns, develops, and operates midstream assets. Western Gas Equity Partners, LP (WGP), a publicly traded consolidated subsidiary, is a limited partnership that owns interests in WES. At December 31, 2015, Anadarko's ownership interest in WGP consisted of an 87.3% limited partner interest and the entire non-economic general partner interest. At December 31, 2015, WGP's ownership interest in WES consisted of a 34.6% limited partner interest, the entire 1.8% general partner interest, and all of the WES incentive distribution rights. At December 31, 2015, Anadarko also owned an 8.5% limited partner interest in WES through other subsidiaries.

At the end of 2015, Anadarko had 40 gathering systems and 54 processing and treating plants located throughout major onshore producing basins in Wyoming, Colorado, Utah, New Mexico, Kansas, Oklahoma, Pennsylvania, and Texas. In 2015, the Company's midstream activity was concentrated in liquids-rich growth areas such as Wattenberg, the Delaware basin, and the Eagleford shale, as well as in the Marcellus shale dry-gas play. In 2016, the Company expects its midstream investment to focus on the Delaware basin to build infrastructure for future Wolfcamp development.

Wattenberg The Company placed into service a second 300-MMcf/d train at its Lancaster cryogenic processing plant. The plant supports increasing production from horizontal drilling in the Niobrara development, helping to relieve processing constraints and improve recoveries of NGLs in the basin. Three new compressor stations were placed online in 2015, which increased compression capacity by 180 MMcf/d. In addition, the Company neared completion of its COSF and will commission the facility in early 2016. The COSF, capable of handling 125 MBbls/d, will increase oil recoveries, enhance efficiencies of tank batteries, lower operating expenses, and further reduce impacts on the environment. Construction of the Saddlehorn pipeline, in which Anadarko has a 20% equity ownership, began in 2015. In November 2015, Saddlehorn Pipeline Company, LLC combined with Grand Mesa to form a single pipeline project, which enhances economics by reducing capital requirements. The combined pipeline, with an initial capacity of 340 MBbls/d, is planned to deliver various grades of oil from the DJ basin to storage facilities in Cushing, Oklahoma and is expected to be operational by mid-2016. Saddlehorn Pipeline Company, LLC will own an initial 190 MBbls/d of capacity with sole expansion rights. Also, the Company elected to participate in an expansion of the White Cliffs oil pipeline to increase the total capacity from 152 MBbls/d to approximately 215 MBbls/d. The expansion will be executed in stages throughout the first half of 2016. Management believes that Anadarko is well-positioned with its oil and NGLs transportation capacity, which includes transport by pipeline, rail, and truck.

Delaware Basin In 2015, the Company expanded its midstream infrastructure for Bone Spring, Wolfcamp, and Avalon production in the Delaware basin of West Texas, installing a total of 177 miles of oil and gas gathering lines. Three central production facility expansions were completed in early 2015 that added 30 MBbls/d of capacity. In addition, four new central gathering facilities (CGFs) were installed and two existing CGFs were expanded to add a total of 110 MMcf/d of compression capacity. Additional CGFs within the field are planned for 2016. In 2014, the Company entered into a joint-venture agreement with a third-party operator to construct the Mi Vida plant, a 200-MMcf/d cryogenic plant located in Loving County, Texas. The Mi Vida plant came online in May 2015 and is processing in excess of 200 MMcf/d.

In November 2014, WES acquired Nuevo Midstream, LLC (Nuevo). Following the acquisition, WES changed the name of Nuevo to Delaware Basin Midstream, LLC (DBM). The DBM assets acquired by WES continue to be upgraded and enhanced to meet the producer gathering and processing needs in the region. The assets include a 300-MMcf/d cryogenic gas-processing plant. In December 2015, there was an initial fire and secondary explosion at the processing facility within the DBM complex. There were no serious injuries and the majority of damage from the incident was to the liquid-handling facilities and the amine-treating units at the inlet of the complex. Train II (with capacity of 100 MMcf/d) sustained the most damage of the processing trains and is expected to be returned to service by the end of 2016. Train III (with capacity of 200 MMcf/d) experienced minimal damage and is expected to be able to accept limited deliveries of gas by the end of the first quarter of 2016, and it is expected to return to full service by the end of the second quarter of 2016, along with new liquid-handling and amine-treating facilities. There was no damage to Trains IV and V (each with a capacity of 200 MMcf/d), which were under construction at the time of the incident. Train IV is expected to come online during the first half of 2016 and Train V is expected to come online during the second half of 2016. WES has a property damage insurance policy designed to cover costs to repair or rebuild damaged assets (less a minimal deductible), and business interruption insurance designed to cover lost earnings after January 2, 2016. Insurance claims are in process under both of these policies.

Greater Natural Buttes The Chipeta plant's total processing capacity (cryogenic and refrigeration) is approximately 1 Bcf/d with cryogenic processing capacity of 550 MMcf/d. Chipeta's third-party pipeline interconnect has added over 100 MMcf/d of natural-gas supply to the plant. In 2015, the Company continued to implement optimization projects to improve reliability and efficiency.

Eagleford In the Eagleford shale, Anadarko continued the expansion of its infield gathering system with the completion of approximately 20 miles of gathering pipelines and laterals that connected 16 new central production facilities. The 200-MMcf/d operated Brasada natural-gas cryogenic processing plant continued steady operations at capacity.

East Texas/North Louisiana In East Texas, the Company continued to expand its midstream infrastructure for Cotton Valley Taylor and Haynesville production in 2015. The high-pressure Haynesville gathering system and related water and condensate infrastructure were expanded in the Carthage area to handle the continued growth associated with the Haynesville natural-gas production. Additionally, Anadarko retained access to 420 MMcf/d of firm-processing capacity for the Company's current and future development in East Texas.

Marcellus In the Marcellus shale, Anadarko continued to expand its gathering system in Lycoming and Bradford Counties in Pennsylvania. In 2015, the Company connected 2 Anadarko-operated wells and 25 nonoperated wells and constructed 42 miles of new pipeline. The Company commissioned three compressor stations in Lycoming County, which allowed an incremental 127 MMcf/d of low-pressure gathering.

The following provides information regarding the Company's midstream assets by geographic regions:

Area	Asset Type	Miles of Gathering Pipelines	Total Horsepower	2015 Average Net Throughput (MMcf/d)
Rocky Mountains	Gathering, processing, and treating	11,100	779,400	3,200
Southern and Appalachia	Gathering, processing, and treating	6,600	724,000	2,400
Total		17,700	1,503,400	5,600

MARKETING ACTIVITIES

The Company's marketing segment actively manages Anadarko's worldwide oil, condensate, natural-gas, and NGLs sales as well as the Company's anticipated LNG sales. In marketing its production, the Company attempts to minimize market-related shut-ins, maximize realized prices, and manage credit-risk exposure. The Company's sales of oil, condensate, natural gas, and NGLs are generally made at market prices at the time of sale. The Company also purchases oil, condensate, natural gas, and NGLs from third parties, primarily near Anadarko's production areas, to aggregate volumes so the Company is positioned to fully use its transportation, storage, and fractionation capacity; facilitate efforts to maximize prices received; and minimize balancing issues with customers and pipelines during operational disruptions.

The Company sells its products under a variety of contract structures, including indexed, fixed-price, and cost-escalation-based agreements. The Company also engages in limited trading activities for the purpose of generating profits from exposure to changes in market prices of oil, condensate, natural gas, and NGLs. The Company does not engage in market-making practices and limits its marketing activities to oil, natural-gas, NGLs, and LNG commodity contracts. The Company's marketing-risk position is typically a net short position (reflecting agreements to sell oil, natural gas, and NGLs in the future for specific prices) that is offset by the Company's natural long position as a producer (reflecting ownership of underlying oil and natural-gas reserves). See *Commodity-Price Risk* under Item 7A of this Form 10-K.

Oil, Condensate, and NGLs Anadarko's oil, condensate, and NGLs revenues are derived from production in the United States, Algeria, and Ghana. Most of the Company's U.S. oil, condensate, and NGLs production is sold under contracts with prices based on market indices, adjusted for location, quality, and transportation. Product from Algeria is sold by tanker as Saharan Blend, condensate, refrigerated propane, and refrigerated butane to customers primarily in the Mediterranean area. Saharan Blend is high-quality crude that provides refiners large quantities of premium products such as gasoline, diesel, and jet fuel. Oil from Ghana is sold by tanker as Jubilee Oil to customers around the world. Jubilee Oil is high-quality crude that provides refiners large quantities of premium products such as gasoline, diesel, and jet fuel.

Natural Gas Anadarko markets its natural-gas production to maximize value and to reduce the inherent risks of physical commodity markets. Anadarko's marketing segment offers supply-assurance and limited risk-management services at competitive prices as well as other services that are tailored to its customers' needs. The Company may also receive a service fee related to the level of reliability and service required by the customer. The Company controls natural-gas firm-transportation capacity that ensures access to downstream markets, which enables the Company to maximize its natural-gas production. This transportation capacity also provides the opportunity to capture incremental value when price differentials between physical locations exist. The Company stores natural gas in contracted storage facilities to minimize operational disruptions to its ongoing operations and to take advantage of seasonal price differentials. Normally, the Company will have forward contracts in place (physical delivery or financial derivative instruments) to sell stored natural gas at a fixed price.

COMPETITION

The oil and gas business is highly competitive in the exploration for and acquisition of reserves and in the gathering and marketing of oil and gas production. The Company's competitors include national oil companies, major integrated oil and gas companies, independent oil and gas companies, individual producers, gas marketers, and major pipeline companies as well as participants in other industries supplying energy and fuel to consumers.

SEGMENT INFORMATION

For additional information on operations by segment, see *Note 22—Segment Information* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K and for additional information on risk associated with international operations, see *Risk Factors* under Item 1A of this Form 10-K.

EMPLOYEES

The Company had approximately 5,800 employees at December 31, 2015.

REGULATORY AND ENVIRONMENTAL MATTERS

Environmental and Occupational Health and Safety Regulations

Anadarko's business operations are subject to numerous international, provincial, federal, regional, state, tribal, local, and foreign environmental and occupational health and safety laws and regulations. The more significant of these existing environmental and occupational health and safety laws and regulations include the following U.S. laws and regulations, as amended from time to time:

- the U.S. Clean Air Act, which restricts the emission of air pollutants from many sources, imposes various pre-construction, monitoring, and reporting requirements, which the Environmental Protection Agency has relied upon as authority for adopting climate change regulatory initiatives
- the U.S. Federal Water Pollution Control Act, also known as the federal Clean Water Act (CWA), which regulates discharges of pollutants from facilities to state and federal waters and establishes the extent to which waterways are subject to federal jurisdiction and rulemaking as protected waters of the United States
- the U.S. Oil Pollution Act of 1990 (OPA), which subjects owners and operators of vessels, onshore facilities, and pipelines, as well as lessees or permittees of areas in which offshore facilities are located, to liability for removal costs and damages arising from an oil spill in waters of the United States
- U.S. Department of the Interior regulations, which relate to offshore oil and natural-gas operations in U.S. waters and impose obligations for establishing financial assurances for decommissioning activities, liabilities for pollution cleanup costs resulting from operations, and potential liabilities for pollution damages
- the Comprehensive Environmental Response, Compensation and Liability Act of 1980, which imposes liability on generators, transporters, and arrangers of hazardous substances at sites where hazardous substance releases have occurred or are threatening to occur

- the U.S. Resource Conservation and Recovery Act, which governs the generation, treatment, storage, transport, and disposal of solid wastes, including hazardous wastes
- the U.S. Safe Drinking Water Act, which ensures the quality of the nation's public drinking water through adoption of drinking water standards and controlling the injection of waste fluids into below-ground formations that may adversely affect drinking water sources
- the U.S. Emergency Planning and Community Right-to-Know Act, which requires facilities to implement a safety hazard communication program and disseminate information to employees, local emergency planning committees, and response departments on toxic chemical uses and inventories
- the U.S. Occupational Safety and Health Act, which establishes workplace standards for the protection of the health and safety of employees, including the implementation of hazard communications programs designed to inform employees about hazardous substances in the workplace, potential harmful effects of these substances, and appropriate control measures
- the Endangered Species Act, which restricts activities that may affect federally identified endangered and threatened species or their habitats through the implementation of operating restrictions or a temporary, seasonal, or permanent ban in affected areas
- the National Environmental Policy Act, which requires federal agencies, including the Department of the Interior, to evaluate major agency actions having the potential to impact the environment and that may require the preparation of environmental assessments and more detailed environmental impact statements that may be made available for public review and comment

These U.S. laws and regulations, as well as state counterparts, generally restrict the level of pollutants emitted to ambient air, discharges to surface water, and disposals or other releases to surface and below-ground soils and ground water. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil, and criminal penalties; the imposition of investigatory, remedial, and corrective action obligations or the incurrence of capital expenditures; the occurrence of delays in the permitting, development or expansion of projects; and the issuance of injunctions restricting or prohibiting some or all of the Company's activities in a particular area. See *Risk Factors* under Item 1A of this Form 10-K for further discussion on hydraulic fracturing; proposed well control rule for the Outer Continental Shelf; ozone standards; climate change, including methane or other greenhouse gas emissions; and other regulations relating to environmental protection. The ultimate financial impact arising from environmental laws and regulations is neither clearly known nor determinable as new standards, such as air emission standards and water quality standards, continue to evolve.

Many states where the Company operates also have, or are developing, similar environmental laws and regulations governing many of these same types of activities. In addition, many foreign countries where the Company is conducting business also have, or may be developing, regulatory initiatives or analogous controls that regulate Anadarko's environmental-related activities. While the legal requirements imposed under state or foreign law may be similar in form to U.S. laws and regulations, in some cases the actual implementation of these requirements may impose additional, or more stringent, conditions or controls that can significantly alter or delay the permitting, development or expansion of a project or substantially increase the cost of doing business. In addition, environmental laws and regulations, including new or amended legal requirements that may arise in the future to address potential environmental concerns such as air and water impacts, are expected to continue to have an increasing impact on the Company's operations.

The Company has reviewed its potential responsibilities under both OPA and CWA as they relate to the Deepwater Horizon events. In December 2010, the U.S. Department of Justice on behalf of the United States, filed a civil lawsuit in the Louisiana District Court against several parties, including the Company, seeking an assessment of civil penalties under the CWA in an amount to be determined by the U.S. District Court in New Orleans, Louisiana (Louisiana District Court). After previously finding that Anadarko, as a nonoperating investor in the Macondo well, was not culpable with respect to the Deepwater Horizon events, the Louisiana District Court found Anadarko liable for civil penalties under the CWA as a working-interest owner in the Macondo well and entered a judgment of $159.5 million in December 2015. For additional information regarding the Company's potential responsibilities under OPA, the CWA, or other legal requirements, see *Note 15—Contingencies—Deepwater Horizon Events* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

The Company has incurred and will continue to incur operating and capital expenditures, some of which may be material, to comply with environmental and occupational health and safety laws and regulations. Although the Company is not fully insured against all environmental and occupational health and safety risks, and the Company's insurance does not cover any penalties or fines that may be issued by a governmental authority, it maintains insurance coverage that it believes is sufficient based on the Company's assessment of insurable risks and consistent with insurance coverage held by other similarly situated industry participants. Nevertheless, it is possible that other developments, such as stricter and more comprehensive environmental and occupational health and safety laws and regulations as well as claims for damages to property or persons resulting from the Company's operations, could result in substantial costs and liabilities, including administrative, civil, and criminal penalties, to Anadarko.

The Company believes that it is in material compliance with existing environmental and occupational health and safety regulations. Further, the Company believes that the cost of maintaining compliance with these existing laws and regulations will not have a material adverse effect on its business, financial condition, results of operations, or cash flows, but new or more stringently applied existing laws and regulations could increase the cost of doing business, and such increases could be material.

Oil Spill-Response Plan

Domestically, the Company is subject to compliance with the federal Bureau of Safety and Environmental Enforcement (BSEE) regulations, which, among other standards, require every owner or operator of a U.S. offshore lease to prepare and submit for approval an oil spill-response plan prior to conducting any offshore operations. The submitted plan is required to provide a detailed description of actions to be taken in the event of a spill; identify contracted spill-response equipment, materials, and trained personnel; and stipulate the time necessary to deploy identified resources in the event of a spill. The BSEE regulations may be amended, resulting in more stringent requirements as changes to the amount and type of spill-response resources to which an owner or operator must maintain ready access. Accordingly, resources available to the Company may change to satisfy any new regulatory requirements or to adapt to changes in the Company's operations.

Anadarko has in place and maintains both Regional (Central and Western Gulf of Mexico) and Sub-Regional (Eastern Gulf of Mexico) Oil Spill-Response Plans (Plans) for the Company's Gulf of Mexico operations. The Plans set forth procedures for a rapid and effective response to spill events that may occur as a result of Anadarko's operations. The Plans are reviewed by the Company at least annually and updated as necessary. Drills are conducted by the Company at least annually to test the effectiveness of the Plans and include the participation of spill-response contractors, representatives of Clean Gulf Associates (CGA, a not-for-profit association of production and pipeline companies operating in the Gulf of Mexico contractually engaged by the Company for such matters), and representatives of relevant governmental agencies. The Plans and any revisions to the Plans must be approved by the BSEE.

As part of the Company's oil spill-response preparedness, and as set forth in the Plans, Anadarko maintains membership in CGA and has an employee representative on the executive committee of CGA. CGA was created to provide a means of effectively staging response equipment and to provide effective spill-response capability for its member companies operating in the Gulf of Mexico. CGA equipment includes, among other things, skimming vessels, barges, boom, and dispersants. CGA has executed a support contract with T&T Marine to coordinate bareboat charters and to provide for expanded response support. T&T Marine is responsible for inspecting, maintaining, storing, and staging CGA equipment. T&T Marine has positioned CGA's equipment and materials in a ready state at various staging areas around the Gulf of Mexico. T&T Marine has service contracts in place with domestic environmental contractors as well as with other companies that provide for support services during the execution of spill-response activities.

Anadarko is also a member of the Marine Preservation Association, which provides full access to the Marine Spill Response Corporation (MSRC) cooperative. In the event of a spill, MSRC stands ready to mobilize all of its equipment and materials. MSRC has a fleet of dedicated Responder Class Oil Spill-Response Vessels (OSRVs), designed and built to recover spilled oil.

MSRC has equipment housed for the Atlantic Region, the Gulf of Mexico Region, the California Region, and the Pacific Northwest Region. Their equipment includes, among other things, skimmers, OSRVs, fast response vessels, barges, storage bladders, work boats, ocean boom, and dispersant.

The Company has also entered into a contractual commitment to access subsea intervention, containment, capture, and shut-in capacity for deepwater exploration wells. Marine Well Containment Company (MWCC) is open to oil and gas operators in the Gulf of Mexico and provides members access to oil spill-response equipment and services on a per-well fee basis. Anadarko has an employee representative on the executive committee of MWCC, and this employee currently serves as its Chair. MWCC members have access to a containment system that is planned for use in deepwater depths of up to 10,000 feet with containment capacity of 100 MBbls/d of liquids and flare capability for 200 MMcf/d of natural gas.

Anadarko retains geospatial and satellite imagery services through the MDA Corporation (MDA) to provide coverage over the Company's Gulf of Mexico operations. MDA owns and maintains two radar satellites, which provide all-weather surveillance and imagery available to assist in identifying areas of concern on the surface waters of the Gulf of Mexico. The Company has agreements with Waste Management, Inc. and Clean Harbors to assist in the proper disposal of contaminated and hazardous waste soil and debris. In addition, Anadarko has agreements with HDR Engineering, Inc. for assistance with subsea dispersant applications. The Company also has agreements with TDI-Brooks International for its scientific research vessels to properly monitor the effectiveness of the dispersant application and the health of the ecosystem. The Company also has agreements with Scientific and Environmental Associates, Inc. (SEA) for assistance with surface dispersant applications. SEA is a scientific support consulting firm providing expertise in surface-dispersion applications and efficacy monitoring.

Anadarko has emergency and oil spill-response plans in place for each of its exploration and operational activities around the globe. Each plan is intended to satisfy the requirements of relevant local or national authorities, describes the actions the Company is expected to take in the event of an incident, includes drills conducted by the Company at least annually, and includes reference to external resources that may become necessary in the event of an incident. Included in these external resources is the Company's contract with Oil Spill Response Limited (OSRL), a global emergency and oil spill-response organization headquartered in London.

OSRL has an aircraft available for dispersant application or equipment transport. OSRL also has a number of active recovery boom systems and a range of booms that can be used for offshore, nearshore, or shoreline responses. In addition, OSRL provides, among other things, a range of communications equipment, safety equipment, transfer pumps, dispersant application systems, temporary storage equipment, power packs and generators, small inflatable vessels, rigid inflatable boats, work boats, and fast response vessels. OSRL also has a wide range of oiled wildlife equipment in conjunction with the Sea Alarm Foundation.

In addition to Anadarko's membership in or access to CGA, MSRC, OSRL, and MWCC, the Company participates in industry-wide task forces, which are currently studying improvements in both gaining access to and controlling blowouts in subsea environments. Two such task forces are the Subsea Well Control and Containment Task Force and the Oil Spill Task Force.

TITLE TO PROPERTIES

As is customary in the oil and gas industry, a preliminary title review is conducted at the time properties believed to be suitable for drilling operations are acquired by the Company. Prior to the commencement of drilling operations, thorough title examinations of the drill site tracts are conducted by third-party attorneys, and curative work is performed with respect to significant defects, if any, before proceeding with operations. Anadarko believes the title to its leasehold properties is good, defensible, and customary with practices in the oil and gas industry, subject to such exceptions that, in the opinion of legal counsel for the Company, do not materially detract from the use of such properties.

Leasehold properties owned by the Company are subject to royalty, overriding royalty, and other outstanding interests customary in the industry. The properties may be subject to burdens such as liens incident to operating agreements, current taxes, development obligations under oil and gas leases and other encumbrances, easements, and restrictions. Anadarko does not believe any of these burdens will materially interfere with its use of these properties.

EXECUTIVE OFFICERS OF THE REGISTRANT

Name	Age at January 31, 2016	Position
R. A. Walker	58	Chairman, President and Chief Executive Officer
Robert P. Daniels	57	Executive Vice President, International and Deepwater Exploration
Robert G. Gwin	52	Executive Vice President, Finance and Chief Financial Officer
Darrell E. Hollek	58	Executive Vice President, U.S. Onshore Exploration and Production
Mitchell W. Ingram	53	Executive Vice President, Global LNG
James J. Kleckner	58	Executive Vice President, International and Deepwater Operations
Robert K. Reeves	58	Executive Vice President, Law and Chief Administrative Officer
Christopher O. Champion	46	Vice President, Chief Accounting Officer and Controller

Mr. Walker was named Chairman of the Board of the Company in May 2013, in addition to the role of Chief Executive Officer and director, both of which he assumed in May 2012, and the role of President, which he assumed in February 2010. He previously served as Chief Operating Officer from March 2009 until his appointment as Chief Executive Officer. He served as Senior Vice President, Finance and Chief Financial Officer from September 2005 until March 2009. From August 2007 until March 2013, he served as director of Western Gas Holdings, LLC (WGH), the general partner of WES, and served as its Chairman of the Board from August 2007 to September 2009. Mr. Walker served as a director of Western Gas Equity Holdings, LLC (WGEH), the general partner of WGP, from September 2012 until March 2013. Mr. Walker served as a director of Temple-Inland Inc. from November 2008 to February 2012 and a director of CenterPoint Energy, Inc. from April 2010 to April 2015, and has served as a director of BOK Financial Corporation since April 2013.

Mr. Daniels was named Executive Vice President, International and Deepwater Exploration in May 2013 and previously served as Senior Vice President, International and Deepwater Exploration since July 2012. Prior to these positions, he served as Senior Vice President, Worldwide Exploration since December 2006 and served as Senior Vice President, Exploration and Production since May 2004. Prior to that position, he served as Vice President, Canada since July 2001. Mr. Daniels also served in various managerial roles in the Exploration Department for Anadarko Algeria Company, LLC. He has worked for the Company since 1985.

Mr. Gwin was named Executive Vice President, Finance and Chief Financial Officer in May 2013 and previously served as Senior Vice President, Finance and Chief Financial Officer since March 2009 and Senior Vice President since March 2008. He also has served as Chairman of the Board of WGH since October 2009 and as a director since August 2007. Additionally, Mr. Gwin has served as Chairman of the Board of WGEH since September 2012, and served as President of WGH from August 2007 to September 2009 and as Chief Executive Officer of WGH from August 2007 to January 2010. He joined Anadarko in January 2006 as Vice President, Finance and Treasurer and served in that capacity until March 2008. He has served as Chairman of the Board of LyondellBasell Industries N.V. since August 2013 and as a director since May 2011.

Mr. Hollek was named Executive Vice President, U.S. Onshore Exploration and Production in April 2015. Prior to this position, he served as Senior Vice President, Deepwater Americas Operations since May 2013. Prior to this position, he served as Vice President, Operations since May 2007. Mr. Hollek joined Anadarko upon the acquisition of Kerr-McGee Corporation in August 2006. He has held positions of increasing responsibility with Anadarko and Kerr-McGee Corporation, where he began his career, including management roles in the Gulf of Mexico; U.S. onshore; and Environmental, Health, Safety and Regulatory. Mr. Hollek has served as a director of WGH and WGEH since May 2015.

Mr. Ingram was named Executive Vice President, Global LNG in November 2015. Prior to joining Anadarko, Mr. Ingram was with BG Group since 2006, where he served as a member of the Executive Committee in the role of Executive Vice President—Technical since March 2015. Previously, he held positions of increasing responsibility with the company's LNG project in Queensland, Australia, where he served as Managing Director of QGC, a BG Group business, since April 2014, Deputy Managing Director since September 2013, and Project Director of the Queensland Curtis LNG project since May 2012. From 2006 to May 2012, Mr. Ingram was Asset General Manager of BG Group's Karachaganak interest in Kazakhstan. He joined BG Group after 20 years with Occidental Oil & Gas where he held several U.K. and international leadership positions in project management, development, and operations.

Mr. Kleckner was named Executive Vice President, International and Deepwater Operations in May 2013. Prior to this position, he served as Vice President, Operations for the Rockies region since May 2007. Mr. Kleckner joined Anadarko upon the acquisition of Kerr-McGee Corporation in August 2006. He has held positions of increasing responsibility with Anadarko and Kerr-McGee Corporation, including management roles in the North Sea, South America, China, the Gulf of Mexico, and U.S. onshore. Prior to joining Kerr-McGee Corporation, Mr. Kleckner was in the oil and natural-gas industry with Oryx Energy Company and its predecessor, Sun Oil Company.

Mr. Reeves was named Executive Vice President, Law and Chief Administrative Officer in September 2015 and previously served as Executive Vice President, General Counsel and Chief Administrative Officer since May 2013 and as Senior Vice President, General Counsel and Chief Administrative Officer since February 2007. He also served as Chief Compliance Officer from July 2012 to May 2013. He served as Corporate Secretary from February 2007 to August 2008. He previously served as Senior Vice President, Corporate Affairs & Law and Chief Governance Officer since 2004. Prior to joining Anadarko, he served as Executive Vice President, Administration and General Counsel of North Sea New Ventures from 2003 to 2004 and as Executive Vice President, General Counsel and Secretary of Ocean Energy, Inc. and its predecessor companies from 1997 to 2003. He has served as a director of Key Energy Services, Inc., a publicly traded oilfield services company, since October 2007, as a director of WGH since August 2007, and as a director of WGEH since September 2012.

Mr. Champion was named Vice President, Chief Accounting Officer and Controller in June 2015. Prior to joining Anadarko, Mr. Champion was an Audit Partner with KPMG LLP since October 2003 and served as KPMG's National Audit Leader for Oil and Natural Gas since 2008. He began his career at Arthur Andersen LLP in 1992 before joining KPMG LLP in 2002 as a senior audit manager.

Officers of Anadarko are elected each year at the first meeting of the Board following the annual meeting of stockholders, the next of which is expected to occur on May 10, 2016, and hold office until their successors are duly elected and qualified. There are no family relationships between any directors or executive officers of Anadarko.

Item 1A. Risk Factors

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

Unless the context otherwise requires, the terms "Anadarko" and "Company" refer to Anadarko Petroleum Corporation and its consolidated subsidiaries. The Company has made in this Form 10-K, and may from time to time make in other public filings, press releases, and management discussions, forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended, concerning the Company's operations, economic performance, and financial condition. These forward-looking statements include, among other things, information concerning future production and reserves, schedules, plans, timing of development, contributions from oil and gas properties, marketing and midstream activities, and also include those statements preceded by, followed by, or that otherwise include the words "may," "could," "believes," "expects," "anticipates," "intends," "estimates," "projects," "target," "goal," "plans," "objective," "should," "would," "will," "potential," "continue," "forecast," "future," "likely," "outlook," or similar expressions or variations on such expressions. For such statements, the Company claims the protection of the safe harbor for forward-looking statements contained in the Private Securities Litigation Reform Act of 1995. Although the Company believes that the expectations reflected in such forward-looking statements are reasonable, it can give no assurance that such expectations will be realized. Anadarko undertakes no obligation to publicly update or revise any forward-looking statements whether as a result of new information, future events, or otherwise.

These forward-looking statements involve risk and uncertainties. Important factors that could cause actual results to differ materially from the Company's expectations include, but are not limited to, the following risks and uncertainties:

- *the Company's assumptions about energy markets*
- *production and sales volume levels*
- *levels of oil, natural-gas, and natural-gas liquids (NGLs) reserves*
- *operating results*
- *competitive conditions*
- *technology*
- *availability of capital resources, levels of capital expenditures, and other contractual obligations*
- *supply and demand for, the price of, and the commercialization and transporting of oil, natural gas, NGLs, and other products or services*
- *volatility in the commodity-futures market*
- *weather*
- *inflation*
- *availability of goods and services, including unexpected changes in costs*
- *drilling risks*
- *processing volumes and pipeline throughput*
- *general economic conditions, nationally, internationally, or in the jurisdictions in which the Company is, or in the future may be, doing business*
- *the Company's inability to timely obtain or maintain permits or other governmental approvals, including those necessary for drilling and/or development projects*
- *legislative or regulatory changes, including changes relating to hydraulic fracturing; retroactive royalty or production tax regimes; deepwater drilling and permitting regulations; derivatives reform; changes in state, federal, and foreign income taxes; environmental regulation; environmental risks; and liability under federal, state, foreign, and local environmental laws and regulations*

- *the ability of BP Exploration & Production Inc. (BP) to meet its indemnification obligations to the Company for Deepwater Horizon events, including, among other things, damage claims arising under the Oil Pollution Act of 1990 (OPA), claims for natural resource damages (NRD) and associated damage-assessment costs, and any claims arising under the Operating Agreement (OA) for the Macondo well, as well as the ability of BP Corporation North America Inc. (BPCNA) and BP p.l.c. to satisfy their guarantees of such indemnification obligations*
- *civil or political unrest or acts of terrorism in a region or country*
- *the creditworthiness and performance of the Company's counterparties, including financial institutions, operating partners, and other parties*
- *volatility in the securities, capital, or credit markets and related risks such as general credit, liquidity, and interest-rate risk*
- *the Company's ability to successfully monetize select assets, repay or refinance its debt, and the impact of changes in the Company's credit ratings*
- *disruptions in international oil, NGLs, and condensate cargo shipping activities*
- *physical, digital, internal, and external security breaches*
- *supply and demand, technological, political, governmental, and commercial conditions associated with long-term development and production projects in domestic and international locations*
- *other factors discussed below and elsewhere in this Form 10-K, and in the Company's other public filings, press releases, and discussions with Company management*

RISK FACTORS

Oil, natural-gas, and NGLs price volatility, including the recent decline in the price for these commodities, could adversely affect our financial condition and results of operations.

Prices for oil, natural gas, and NGLs can fluctuate widely. For example, New York Mercantile Exchange (NYMEX) West Texas Intermediate oil prices have been volatile and ranged from a high of $107.26 per barrel in June 2014 to a low of $26.21 per barrel in February 2016. Also, NYMEX Henry Hub natural-gas prices have been volatile and ranged from a high of $6.15 per million British thermal units (MMBtu) in February 2014 to a low of $1.76 per MMBtu in December 2015. The duration and magnitude of the decline in oil and natural-gas prices cannot be predicted. Our revenues, operating results, cash flows from operations, capital budget, and future growth rates are highly dependent on the prices we receive for our oil, natural gas, and NGLs. The markets for oil, natural gas, and NGLs have been volatile historically and may continue to be volatile in the future. Factors influencing the prices of oil, natural gas, and NGLs are beyond our control. These factors include, but are not limited to, the following:

- the domestic and worldwide supply of, and demand for, oil, natural gas, and NGLs
- volatility and trading patterns in the commodity-futures markets
- the cost of exploring for, developing, producing, transporting, and marketing oil, natural gas, and NGLs
- the level of global oil and natural-gas inventories
- weather conditions
- the level of U.S. exports of oil, condensate, liquefied natural gas, or NGLs
- the ability of the members of the Organization of the Petroleum Exporting Countries (OPEC) and other producing nations to agree to and maintain production levels
- the worldwide military and political environment, civil and political unrest in Africa and the Middle East, uncertainty or instability resulting from the escalation or additional outbreak of armed hostilities, or acts of terrorism in the United States or elsewhere
- the effect of worldwide energy conservation and environmental protection efforts

- the price and availability of alternative and competing fuels
- the level of foreign imports of oil, natural gas, and NGLs
- domestic and foreign governmental laws, regulations, and taxes
- the proximity to, and capacity of, natural-gas pipelines and other transportation facilities
- general economic conditions worldwide

The long-term effect of these and other factors on the prices of oil, natural gas, and NGLs is uncertain. Prolonged or further declines in these commodity prices may have the following effects on our business:

- adversely affecting our financial condition, liquidity, ability to finance planned capital expenditures, and results of operations
- reducing the amount of oil, natural gas, and NGLs that we can produce economically
- causing us to delay or postpone some of our capital projects
- reducing our revenues, operating income, or cash flows
- reducing the amounts of our estimated proved oil, natural-gas, and NGLs reserves
- reducing the carrying value of our oil, natural-gas, and midstream properties due to recognizing additional impairments of proved properties, unproved properties, exploration assets, and midstream facilities
- reducing the standardized measure of discounted future net cash flows relating to oil, natural-gas, and NGLs reserves
- limiting our access to, or increasing the cost of, sources of capital such as equity and long-term debt

A downgrade in our credit rating could negatively impact our cost of and ability to access capital.

As of December 31, 2015, our long-term debt was rated "BBB" with a stable outlook by both Standard and Poor's (S&P) and Fitch Ratings (Fitch), and our commercial paper program was rated "A-2" by S&P and "F2" by Fitch. Our long-term debt was rated "Baa2" with a stable outlook and our commercial paper program was rated "P2" by Moody's Investors Service (Moody's) until December 16, 2015, when Moody's announced that it had placed both ratings under review for downgrade along with the ratings of 28 other U.S. exploration and production companies and their related subsidiaries. In February 2016, S&P affirmed our "BBB" rating and changed the outlook from stable to negative. As of the time of filing this Form 10-K, neither Fitch nor Moody's had announced any change to our credit ratings; however, we cannot be assured that our credit ratings will not be downgraded. Any downgrade in our credit ratings could negatively impact our cost of capital, and a downgrade to a level that is below investment grade could also adversely affect our ability to effectively execute aspects of our strategy or to raise debt in the public debt markets.

In the event of a downgrade in our credit rating to a level that is below investment grade, we may be required to post collateral in the form of letters of credit or cash as financial assurance of our performance under certain contractual arrangements such as pipeline transportation contracts and oil and gas sales contracts. At December 31, 2015, there were no letters of credit or cash provided as assurance of our performance under these type of contractual arrangements with respect to credit-risk-related contingent features. If our credit ratings had been downgraded to a level below investment grade as of December 31, 2015, the collateral required to be posted under these arrangements would have been $460 million. Additionally, certain of these arrangements contain financial assurances language that may, under certain circumstances, permit our counterparties to request additional collateral.

Furthermore, in the event of a downgrade to a level that is below investment grade, the credit thresholds with our derivative counterparties may be reduced or, in certain cases, eliminated, which may require the posting of additional collateral in the form of letters of credit or cash. The aggregate fair value of all derivative instruments with credit-risk-related contingent features for which a net liability position existed on December 31, 2015, was $1.3 billion, net of collateral. As of December 31, 2015, $58 million was posted as cash collateral with our derivative counterparties. For additional information, see *Note 9—Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

We are subject to complex laws and regulations relating to environmental protection that can adversely affect the cost, manner, and feasibility of doing business.

Our operations and properties are subject to numerous federal, provincial, regional, state, tribal, local, and foreign laws and regulations governing the release of pollutants or otherwise relating to environmental protection. These laws and regulations govern the following, among other things:

- issuance of permits in connection with exploration, drilling, production, and midstream activities
- drilling activities on certain lands lying within wilderness, wetlands, and other protected areas
- types, quantities, and concentrations of emissions, discharges, and authorized releases
- generation, management, and disposition of waste materials
- offshore oil and natural-gas operations and decommissioning of abandoned facilities
- reclamation and abandonment of wells and facility sites
- remediation of contaminated sites
- protection of endangered species

These laws and regulations may impose substantial liabilities for our failure to comply or for any contamination resulting from our operations, including the assessment of administrative, civil, and criminal penalties; the imposition of investigatory, remedial, and corrective action obligations or the incurrence of capital expenditures; the occurrence of delays in the permitting, development, or expansion of projects; and the issuance of injunctions restricting or prohibiting some or all of our activities in a particular area. Moreover, changes in, or reinterpretations of, environmental laws and regulations governing areas where we operate may negatively impact our operations. Examples of recent proposed and final regulations include the following:

- *Proposed Outer Continental Shelf Well Control Rule*. In April 2015, the Bureau of Safety and Environmental Enforcement (BSEE) issued a notice of proposed rulemaking entitled Oil and Sulfur Operations on the Outer Continental Shelf - Blowout Preventer Systems and Well Control that focuses on well blowout preventer systems and well control with respect to operations on the Outer Continental Shelf. The proposed rule requires, among other things, incorporation of the latest industry standards establishing minimum baseline standards for the design, manufacture, repair, and maintenance of blowout preventers as well as more controls over the maintenance and repair of blowout preventers. This rulemaking is expected to be finalized in 2016.
- *Ground-Level Ozone Standards.* In October 2015, the U.S. Environmental Protection Agency (EPA) issued a final rule under the Clean Air Act, lowering the National Ambient Air Quality Standard (NAAQS) for ground-level ozone from 75 parts per billion to 70 parts per billion under both the primary and secondary standards to provide requisite protection of public health and welfare, respectively. The final rule became effective in December 2015. Certain areas of the country in compliance with the ground-level ozone NAAQS standard may be reclassified as non-attainment and such reclassification may make it more difficult to construct new or modified sources of air pollution in newly designated non-attainment areas. Moreover, states are expected to implement more stringent regulations, which could apply to our operations. Compliance with this final rule could, among other things, require installation or new emission controls on some of our equipment, result in longer permitting timelines, and significantly increase our capital expenditures and operating costs.
- *Reduction of Methane Emissions by the Oil and Gas Industry.* In August 2015, the EPA proposed rules that will establish emission standards for methane from certain new and modified oil and natural-gas production and natural-gas processing and transmission facilities as part of the Obama Administration's efforts to reduce methane emissions from the oil and natural-gas sector by up to 45 percent from 2012 levels by 2025. The EPA's proposed rule package includes standards to address emissions of methane from equipment and processes across the source category, including hydraulically-fractured oil and natural-gas well completions, fugitive emissions from well sites and compressors, and equipment leaks at natural-gas processing plants and pneumatic pumps. The EPA is expected to finalize these rules in 2016.

- *Reduction of Greenhouse Gas Emissions.* The U.S. Congress and the EPA, in addition to some state and regional efforts, have in recent years considered legislation or regulations to reduce emissions of greenhouse gases (GHGs). These efforts have included consideration of cap-and-trade programs, carbon taxes, and GHG reporting and tracking programs. In the absence of federal GHG-limiting legislations, the EPA has determined that GHG emissions present a danger to public health and the environment and has adopted regulations that, among other things, restrict emissions of GHGs under existing provisions of the Clean Air Act and may require the installation of "best available control technology" to limit emissions of GHGs from any new or significantly modified facilities that we may seek to construct in the future if they would otherwise emit large volumes of GHGs together with other criteria pollutants. Also, certain of our operations are subject to EPA rules requiring the monitoring and annual reporting of GHG emissions from specified onshore and offshore production sources. On an international level, the United States is one of almost 200 nations that, in December 2015, agreed to an international climate change agreement in Paris, France that calls for countries to set their own GHG emissions targets and be transparent about the measures each country will use to achieve its GHG emissions targets.

These and other regulatory changes could significantly increase our capital expenditures and operating costs or could result in delays to or limitations on our exploration and production activities, which could have an adverse effect on our financial condition, results of operations, or cash flows. For a description of certain environmental proceedings in which we are involved, see *Legal Proceedings* under Item 3 and *Note 15—Contingencies* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Changes in laws or regulations regarding hydraulic fracturing or other oil and natural-gas operations could increase our costs of doing business, impose additional operating restrictions or delays, and adversely affect our production.

Hydraulic fracturing is an essential and common practice used to stimulate production of oil and natural gas from dense subsurface rock formations such as shales. We routinely apply hydraulic-fracturing techniques in many of our U.S. onshore oil and natural-gas drilling and completion programs. The process involves the injection of water, sand, and additives under pressure into a targeted subsurface formation to fracture the surrounding rock and stimulate production.

Hydraulic fracturing is typically regulated by state oil and natural-gas commissions. However, several federal agencies have also asserted regulatory authority over certain aspects of the process. For example, the EPA issued Clean Air Act final regulations in 2012 and proposed additional Clean Air Act regulations in August 2015 governing performance standards for the oil and natural-gas industry; proposed in April 2015 effluent limitations guidelines that waste water from shale natural-gas extraction operations must meet before discharging to a treatment plant; and issued in 2014 a prepublication of its Advance Notice of Proposed Rulemaking regarding Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. Also, the Bureau of Land Management (BLM) published a final rule in March 2015 that establishes new or more stringent standards for performing hydraulic fracturing on federal and Indian lands but, in September 2015, the U.S. District Court of Wyoming issued a preliminary injunction barring implementation of this rule, which order the BLM could appeal and is being separately appealed by certain environmental groups. Also, from time to time, legislation has been introduced, but not enacted, in Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. In the event that a new federal level of legal restrictions relating to the hydraulic-fracturing process is adopted in areas where we operate, we may incur additional costs to comply with such federal requirements that may be significant in nature, and also could become subject to additional permitting requirements and experience added delays or curtailment in the pursuit of exploration, development, or production activities.

Certain states in which we operate, including Colorado, Pennsylvania, Louisiana, Texas, and Wyoming, have adopted, and other states are considering adopting, regulations that could impose new or more stringent permitting, disclosure, or other regulatory requirements on hydraulic-fracturing operations, including subsurface water disposal. States could elect to prohibit hydraulic fracturing altogether, following the approach taken by the State of New York in 2015. In addition to state laws, local land use restrictions, such as city ordinances, may restrict drilling in general and/or hydraulic fracturing in particular. For example, several cities in Colorado passed temporary or permanent moratoria on hydraulic fracturing within their respective city limits in 2012 and 2013. Since that time, in response to lawsuits brought by an industry trade group, local district courts struck down the ordinances for certain of those Colorado cities in 2014, primarily on the basis that state law preempts local bans on hydraulic fracturing. A suit brought by the trade group against at least one other Colorado city, Broomfield, remains pending. The cities of Fort Collins and Longmont, among those cities whose ordinances were struck down in 2014, were notified in September 2015 by the Colorado Supreme Court that the high court had agreed to hear their appeals. Notwithstanding attempts at the local level to prohibit hydraulic fracturing, the opportunity exists for cities to adopt local ordinances allowing hydraulic fracturing activities within their jurisdictions while regulating the time, place, and manner of those activities.

In addition, certain interest groups in Colorado opposed to oil and natural-gas development generally, and hydraulic fracturing in particular, have from time to time advanced various ballot initiatives aimed at significantly limiting or preventing oil and natural-gas development. In response to one such set of initiatives, the Governor of Colorado created the Task Force on State and Local Regulation of Oil and Gas Operations (Task Force) in September 2014 to make recommendations to the state legislature regarding the responsible development of Colorado's oil and natural-gas resources. In February 2015, the Task Force made several non-binding recommendations to the Colorado Governor, and recently, the Colorado Oil and Gas Conservation Commission (COGCC) undertook a rulemaking process to implement those recommendations. It is possible that the COGCC could undertake additional rulemaking procedures or the Colorado state legislature could introduce and seek to adopt additional legislation relating to oil and natural-gas operations that could limit or prevent oil and natural-gas development. In addition, several ballot initiatives have been proposed for inclusion on the Colorado state ballot in November 2016. Although it is early in the political process, if approved, these initiatives, or others that may be proposed, could give local governments in Colorado greater authority to limit hydraulic fracturing, require greater distances between certain well sites and occupied structures, or otherwise limit the production and development of oil and natural gas.

In the event that ballot initiatives, local or state restrictions, or prohibitions are adopted and result in more stringent limitations on the production and development of oil and natural gas in areas where we conduct operations, including the Wattenberg field in Colorado, we may incur significant costs to comply with such requirements or may experience delays or curtailment in the permitting or pursuit of exploration, development, or production activities. In addition, we could possibly be limited or precluded in the drilling of wells or in the amounts that we are ultimately able to produce from our reserves. Such compliance costs and delays, curtailments, limitations, or prohibitions could have a material adverse effect on our business, prospects, results of operations, financial condition, and liquidity.

In addition to asserting regulatory authority, a number of federal entities are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. In April 2012, President Obama issued an executive order that established a working group for the purpose of coordinating policy, information sharing, and planning among federal agencies and offices regarding "unconventional natural-gas production," including hydraulic fracturing. In June 2015, the EPA released its draft report on the potential impacts of hydraulic fracturing on drinking water resources, which concluded that hydraulic fracturing activities have not lead to widespread, systemic impacts on drinking water sources in the United States, although there are above and below ground mechanisms by which hydraulic fracturing activities have the potential to impact drinking water sources. However, in January 2016, the EPA's Science Advisory Board provided its comments on the draft study, indicating its concern that the EPA's conclusion of no widespread, systemic impacts on drinking water sources arising from fracturing activities did not reflect the uncertainties and data limitations associated with such impacts, as described in the body of the draft report. The final version of this EPA report remains pending and is expected to be completed in 2016. Such EPA final report, when issued, as well as other studies and initiatives or any future studies, depending on their degree of pursuit and any meaningful results obtained, could spur efforts to further regulate hydraulic fracturing.

We may be subject to claims and liabilities relating to the Deepwater Horizon events that result in losses, notwithstanding BP's indemnification against such losses, as a result of BP's inability to satisfy its indemnification obligations under the Settlement Agreement and BPCNA's and BP p.l.c.'s inability to satisfy their guarantees of BP's indemnification obligations.

In October 2011, we and BP entered into a settlement agreement, mutual releases, and agreement to indemnify relating to the Deepwater Horizon events (Settlement Agreement). Pursuant to the Settlement Agreement, we are fully indemnified by BP against all claims, causes of action, losses, costs, expenses, liabilities, damages, or judgments of any kind arising out of the Deepwater Horizon events, related damage claims arising under OPA, NRD claims and assessment costs, and any claims arising under the OA. This indemnification is guaranteed by BPCNA and, in the event that the net worth of BPCNA declines below an agreed-on amount, BP p.l.c. has agreed to become the sole guarantor. We are not indemnified against penalties and fines, punitive damages, shareholder derivative or securities laws claims, or certain other claims.

In July 2015, BP announced a settlement agreement in principle with the Department of Justice and certain states and local government entities regarding essentially all of the outstanding claims against BP related to the Deepwater Horizon event (BP Settlement) and, in October 2015, lodged a proposed consent decree with the Louisiana District Court. Essentially all claims and liabilities relating to the Deepwater Horizon events that are covered by BP's indemnification obligations under our Settlement Agreement will be resolved as part of the BP Settlement, provided that the consent decree is ultimately approved by the Louisiana District Court. A hearing related to the consent decree is currently scheduled for March 2016. In the event the consent decree is not approved by the Louisiana District Court, any failure or inability on the part of BP to satisfy its indemnification obligations under the Settlement Agreement, or on the part of BPCNA or BP p.l.c. to satisfy their respective guarantee obligations, could subject us to significant monetary liability beyond the terms of the Settlement Agreement, which could have a material adverse effect on our business, prospects, results of operations, financial condition, and liquidity. Furthermore, in certain instances we may be required to recognize a liability for amounts for which we are indemnified in advance of or in connection with recognizing a receivable from BP for the related indemnity payment. Any such liability recognition without collection of the offsetting receivable could adversely impact our results of operations, our financial condition, and our ability to make borrowings. For additional information, see *Note 15—Contingencies—Deepwater Horizon Events* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Our debt and other financial commitments may limit our financial and operating flexibility.

Our total debt was $15.8 billion at December 31, 2015. We also have various commitments for leases, drilling contracts, derivative contracts, firm transportation, and purchase obligations for services and products. Our financial commitments could have important consequences to our business, including, but not limited to, the following:

- increasing our vulnerability to general adverse economic and industry conditions
- limiting our ability to fund future working capital and capital expenditures, to engage in future acquisitions or development activities, or to otherwise fully realize the value of our assets and opportunities because of the need to dedicate a substantial portion of our cash flows from operations to payments on our debt or to comply with any restrictive terms of our debt
- limiting our flexibility in planning for, or reacting to, changes in the industry in which we operate
- placing us at a competitive disadvantage compared to our competitors that have less debt and/or fewer financial commitments

Additionally, the credit agreements governing our $3.0 billion five-year senior unsecured revolving credit facility and our $2.0 billion 364-day senior unsecured revolving credit facility contain a number of customary covenants, including a financial covenant requiring maintenance of a consolidated indebtedness to total capitalization ratio of no greater than 65% (excluding the effect of non-cash write-downs), and limitations on certain secured indebtedness, sale-and-leaseback transactions, and mergers and other fundamental changes. Our ability to meet such covenants may be affected by events beyond our control.

Our proved reserves are estimates. Any material inaccuracies in our reserves estimates or assumptions underlying our reserves estimates could cause the quantities and net present value of our reserves to be overstated or understated.

There are numerous uncertainties inherent in estimating quantities of proved reserves, including many factors beyond our control that could cause the quantities and net present value of our reserves to be overstated or understated. The reserves information included or incorporated by reference in this Form 10-K represents estimates prepared by our internal engineers. The procedures and methods for estimating the reserves by our internal engineers were reviewed by independent petroleum consultants; however, no reserves audit was conducted by these consultants. Estimation of reserves is not an exact science. Estimates of economically recoverable oil and natural-gas reserves and of future net cash flows depend on a number of variable factors and assumptions, any of which may cause actual results to vary considerably from these estimates. These factors and assumptions may include, but are not limited to, the following:

- historical production from an area compared with production from similar producing areas
- assumed effects of regulation by governmental agencies and court rulings
- assumptions concerning future oil and natural-gas prices, future operating costs, and capital expenditures
- estimates of future severance and excise taxes, workover costs, and remedial costs

Estimates of reserves based on risk of recovery and estimates of expected future net cash flows prepared by different engineers, or by the same engineers at different times, may vary substantially. Actual production, revenues, and expenditures with respect to our reserves will likely vary from estimates, and the variance may be material. The discounted cash flows included in this Form 10-K should not be construed as the fair value of the estimated oil, natural-gas, and NGLs reserves attributable to our properties. The estimated discounted future net cash flows from proved reserves are based on the average beginning-of-month prices during the 12-month period for the respective year. Actual future prices and costs may differ materially from the SEC regulation-compliant prices used for purposes of estimating future discounted net cash flows from proved reserves. Therefore, reserves quantities will change when actual prices increase or decrease.

Failure to replace reserves may negatively affect our business.

Our future success depends on our ability to find, develop, or acquire additional oil and natural-gas reserves that are economically recoverable. Our proved reserves generally decline when reserves are produced, unless we conduct successful exploration or development activities, acquire properties containing proved reserves, or both. We may be unable to find, develop, or acquire additional reserves on an economic basis. Furthermore, if oil and natural-gas prices increase, our costs for finding or acquiring additional reserves could also increase.

Our domestic operations are subject to governmental risks that may impact our operations.

Our domestic operations have been, and at times in the future may be, affected by political developments and are subject to complex federal, provincial, regional, state, tribal, local, and other laws and regulations such as restrictions on production, permitting, changes in taxes, deductions, royalties and other amounts payable to governments or governmental agencies, price or gathering-rate controls, and hydraulic fracturing and environmental protection regulations. To conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals, and certificates from various federal, provincial, regional, state, tribal, and local governmental authorities. We may incur substantial costs to maintain compliance with these existing laws and regulations. Our costs of compliance may increase if existing laws, including environmental and tax laws and regulations, are revised or reinterpreted, or if new laws and regulations become applicable to our operations such as the adoption of government-payment-transparency regulations. For example, from time to time, deficit reduction or tax reform legislation has been proposed that could adversely affect our business, financial condition, results of operations, or cash flows. Proposals have included provisions that would, if enacted, (i) eliminate the immediate deduction for intangible drilling and development costs, (ii) eliminate the manufacturing deduction for oil and gas qualified production activities, (iii) eliminate accelerated depreciation for tangible property, and (iv) treat publicly traded partnerships for fossil fuels as C corporations.

Future economic, business, or industry conditions may have a material adverse effect on our results of operations, liquidity, and financial condition.

During the last few years, concerns over inflation, potential default on U.S. debt, energy costs, geopolitical issues, the availability and cost of credit, and uncertainties with regard to European sovereign debt, have contributed to increased economic uncertainty and diminished expectations for the global economy. Concerns about global economic growth have had a significant adverse impact on global financial markets and commodity prices. Continued concerns could cause demand for petroleum products to diminish or stagnate, which could impact the price at which we can sell our oil, natural gas, and NGLs and impede the execution of long-term sales agreements or prices thereunder which are the basis for future LNG production; affect the ability of our vendors, suppliers, and customers to continue operations; and ultimately adversely impact our results of operations, liquidity, and financial condition.

Our results of operations could be adversely affected by goodwill impairments.

As a result of mergers and acquisitions, we had approximately $5.4 billion of goodwill on our Consolidated Balance Sheet at December 31, 2015. Goodwill must be tested at least annually for impairment, and more frequently when circumstances indicate likely impairment. Goodwill is considered impaired to the extent that its carrying amount exceeds its implied fair value. Various factors could reduce the fair value of a reporting unit such as our inability to replace the value of our depleting asset base, difficulty or potential delays in obtaining drilling permits, or other adverse events such as lower oil and natural-gas prices, which could lead to an impairment of goodwill. An impairment of goodwill could have a substantial negative effect on our profitability.

We are vulnerable to risks associated with our offshore operations that could negatively impact our operations and financial results.

We conduct offshore operations in the Gulf of Mexico, Ghana, Mozambique, Colombia, Côte d'Ivoire, New Zealand, Kenya, and other countries. Our operations and financial results could be significantly impacted by conditions in some of these areas because we are vulnerable to certain unique risks associated with operating offshore, including those relating to the following:

- hurricanes and other adverse weather conditions
- oilfield service costs and availability
- compliance with environmental and other laws and regulations
- terrorist attacks such as piracy
- remediation and other costs and regulatory changes resulting from oil spills or releases of hazardous materials
- failure of equipment or facilities

In addition, we conduct some of our exploration in deep waters (greater than 1,000 feet) where operations and decommissioning activities are more difficult and costly than in shallower waters. The deep waters in the Gulf of Mexico, as well as international deepwater locations, lack the physical and oilfield service infrastructure present in shallower waters. As a result, deepwater operations may require significant time between a discovery and the time that we can market our production, thereby increasing the risk involved with these operations.

Additional domestic and international deepwater drilling laws, regulations, and other restrictions; delays in the processing and approval of drilling permits and exploration, development, oil spill-response, and decommissioning plans; and other related developments may have a material adverse effect on our business, financial condition, or results of operations.

In response to the Deepwater Horizon incident in the Gulf of Mexico in 2010, the Bureau of Ocean Energy Management (BOEM) and the BSEE, agencies of the U.S. Department of the Interior, imposed more stringent permitting procedures and regulatory safety and performance requirements for new wells to be drilled in federal waters. Compliance with these more stringent rules and regulations, together with any uncertainties or inconsistencies in current decisions and rulings by governmental agencies, delays in the processing and approval of drilling permits or exploration, development, oil spill-response and decommissioning plans, and possible additional regulatory initiatives could adversely affect or delay new drilling and ongoing development efforts. In addition, new regulatory initiatives may be adopted or enforced by the BOEM and/or the BSEE in the future that could result in additional delays, restrictions, or obligations with respect to oil and natural-gas exploration and production operations conducted offshore. For example, in September 2015, the BOEM issued draft guidance that would bolster supplemental bonding procedures for the decommissioning of offshore wells, platforms, pipelines, and other facilities. The BOEM is expected to issue the draft guidance in the form of a final Notice to Lessees and Operators by no later than early summer 2016. These existing rules, or any new rules, regulations, or legal initiatives could delay or disrupt our operations, increase the risk of expired leases due to the time required to develop new technology, result in increased supplemental bonding and costs, and limit activities in certain areas, or cause us to incur penalties, fines, or shut-in production at one or more of our facilities or result in the suspension or cancellation of leases. Also, if material spill events similar to the Deepwater Horizon incident were to occur in the future, the United States or other countries could elect to again issue directives to temporarily cease drilling activities and, in any event, may from time to time issue further safety and environmental laws and regulations regarding offshore oil and gas exploration and development. We cannot predict with any certainty the full impact of any new laws, regulations, or legal initiatives on our drilling operations or on the cost or availability of insurance to cover the risks associated with such operations. The overall costs to implement and complete any such spill response activities or any decommissioning obligations could exceed estimated accruals, insurance limits, or supplemental bonding amounts, which could result in the incurrence of additional costs to complete.

Further, the deepwater Gulf of Mexico (as well as international deepwater locations) lacks the degree of physical and oilfield service infrastructure present in shallower waters. Therefore, despite our oil spill-response capabilities, it may be difficult for us to quickly or effectively execute any contingency plans related to potential material events in the future.

The matters described above, individually or in the aggregate, could have a material adverse effect on our business, prospects, results of operations, financial condition, and liquidity.

We operate in foreign countries and are subject to political, economic, and other uncertainties.

We have operations outside the United States, including in Algeria, Ghana, Mozambique, Colombia, Côte d'Ivoire, New Zealand, Kenya, and other countries. As a result, we face political and economic risks and other uncertainties with respect to our international operations. These risks may include the following, among other things:

- loss of revenue, property, and equipment or delays in operations as a result of hazards such as expropriation, war, piracy, acts of terrorism, insurrection, civil unrest, and other political risks, including tension and confrontations among political parties
- transparency issues in general and, more specifically, the U.S. Foreign Corrupt Practices Act, the U.K. Bribery Act, and other anti-corruption compliance laws and issues
- increases in taxes and governmental royalties
- unilateral renegotiation of contracts by governmental entities
- redefinition of international boundaries or boundary disputes
- difficulties enforcing our rights against a governmental agency because of the doctrine of sovereign immunity and foreign sovereignty over international operations
- changes in laws and policies governing operations of foreign-based companies
- foreign-exchange restrictions
- international monetary fluctuations and changes in the relative value of the U.S. dollar as compared to the currencies of other countries in which we conduct business

For example, Ghana and Côte d'Ivoire are engaged in a dispute regarding the international maritime boundary between the two countries. As a result, Côte d'Ivoire claims to be entitled to the maritime area, which covers a portion of the Deepwater Tano Block where we are developing the TEN complex. In the event Côte d'Ivoire is successful in its maritime border claims, this development could be materially impacted. Also, Venezuela and Guyana are in a dispute regarding their maritime and land borders in which the two countries have initiated a dialogue. We are unable to ascertain the full impact of this border dispute on future operations in Guyana.

Outbreaks of civil and political unrest and acts of terrorism have occurred in countries in Europe, Africa, and the Middle East, including countries close to or where we conduct operations. Continued or escalated civil and political unrest and acts of terrorism in the countries in which we operate could result in our curtailing operations. In the event that countries in which we operate experience civil or political unrest or acts of terrorism, especially in events where such unrest leads to an unseating of the established government, our operations in such countries could be materially impaired.

Our international operations may also be adversely affected, directly or indirectly, by laws, policies, and regulations of the United States affecting foreign trade and taxation, including U.S. trade sanctions.

Realization of any of the factors listed above could materially and adversely affect our financial condition, results of operations, or cash flows.

Our commodity-price risk-management and trading activities may prevent us from fully benefiting from price increases and may expose us to other risks.

To the extent that we engage in commodity-price risk-management activities to protect our cash flows from commodity-price declines, we may be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, our commodity-price risk-management and trading activities may expose us to the risk of financial loss in certain circumstances, including instances in which the following occur:

- our production is less than the notional volumes
- a widening of price basis differentials occurs between delivery points for our production and the delivery point assumed in the derivative arrangement
- the counterparties to our hedging or other price-risk management contracts fail to perform under those arrangements
- a sudden unexpected event materially impacts oil, natural-gas, or NGLs prices

The enactment of derivatives legislation, and the promulgation of regulations pursuant thereto, could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity-price, interest-rate, and other risks associated with its business.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act), enacted in 2010, requires the Commodity Futures Trading Commission (CFTC) and the SEC to promulgate rules and regulations establishing federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market, including swap clearing and trade execution requirements. While many rules and regulations have been promulgated and are already in effect, other rules and regulations, including the proposed position limits rule, remain to be finalized or effectuated, and therefore, the impact of those rules and regulations on us is uncertain at this time. Moreover, the phase-in threshold for swap dealer *de minimis* purposes is set to expire on December 31, 2017, (and thereby revert from $8 billion to $3 billion) unless the CFTC acts to maintain or change the current $8 billion threshold before that time. The financial reform legislation may require our compliance with a lower *de minimis* threshold, as well as with margin, position limits, clearing, and trade-execution requirements if certain hedging exemptions are unavailable. Although we expect to qualify for exceptions to such requirements for swaps entered to hedge our commercial risks, the application of such requirements, including to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. Moreover, the framework of what qualifies as a bona fide hedge for position-limits purposes is yet uncertain.

The Dodd-Frank Act, and the rules promulgated thereunder, could (i) significantly increase the cost, or decrease the liquidity, of energy-related derivatives we use to hedge against commodity-price fluctuations (including through requirements to post collateral), (ii) materially alter the terms of derivative contracts, and (iii) reduce the availability of derivatives to protect against risks we encounter. If we reduce our use of derivatives as a result of the Dodd-Frank Act and applicable rules and regulations, our cash flow may become more volatile and less predictable, which could adversely affect our ability to plan for and fund capital expenditures. In addition, the European Union and other non-U.S. jurisdictions are implementing regulations with respect to the derivatives market. To the extent we transact with counterparties in foreign jurisdictions, those transactions may become subject to such regulations. At this time, the impact of such regulations is not clear.

Deterioration in the credit or equity markets could adversely affect us.

We have exposure to different counterparties. For example, we have entered into transactions with counterparties in the financial services industry, including commercial banks, investment banks, insurance companies, investment funds, and other institutions. These transactions expose us to credit risk in the event of default by our counterparty. Deterioration in the credit markets may impact the credit ratings of our current and potential counterparties and affect their ability to fulfill existing obligations to us and their willingness to enter into future transactions with us. We have exposure to these financial institutions through our derivative transactions. In addition, if any lender under our credit facilities is unable to fund its commitment, our liquidity will be reduced by an amount up to the aggregate amount of such lender's commitment under our credit facilities. Moreover, to the extent that purchasers of our production rely on access to the credit or equity markets to fund their operations, there is a risk that those purchasers could default in their contractual obligations to us if such purchasers were unable to access the credit or equity markets for an extended period of time.

We are not insured against all of the operating risks to which our business is exposed.

Our business is subject to all of the operating risks normally associated with the exploration for and production, gathering, processing, and transportation of oil and natural gas, including blowouts; cratering and fire; environmental hazards such as natural-gas leaks, oil spills, pipeline and vessel ruptures, and releases of chemicals or other hazardous substances, any of which could result in damage to, or destruction of, oil and natural-gas wells or formations, production facilities, and other property; pollution or other environmental damage; and injury to persons. For protection against financial loss resulting from these operating hazards, we maintain insurance coverage, including insurance coverage for certain physical damage, blowout/loss of control of a well, comprehensive general liability, aviation liability, and worker's compensation and employer's liability. However, our insurance coverage may not be sufficient to cover us against 100% of potential losses arising as a result of the foregoing and for certain risks, such as political risk, business interruption, war, terrorism, and piracy, for which we have limited or no coverage. In addition, we are not insured against all risks in all aspects of our business such as hurricanes. The occurrence of a significant event against which we are not fully insured could have a material adverse effect on our financial condition, results of operations, or cash flows.

Material differences between the estimated and actual timing of critical events may affect the completion of and commencement of production from development projects.

We are involved in several large development projects and the completion of those projects may be delayed beyond our anticipated completion dates. Key factors that may affect the timing and outcome of such projects include the following:

- project approvals by joint-venture partners
- timely issuance of permits and licenses by governmental agencies or legislative and other governmental approvals
- weather conditions
- availability of qualified personnel
- civil and political environment of, and existing infrastructure in, the country or region in which the project is located
- manufacturing and delivery schedules of critical equipment
- commercial arrangements for pipelines and related equipment to transport and market hydrocarbons

Delays and differences between estimated and actual timing of critical events may affect the forward-looking statements related to large development projects and could have a material adverse effect on our results of operations.

The oil and gas exploration and production industry is very competitive, and some of our exploration and production competitors have greater financial and other resources than we do.

The oil and gas business is highly competitive in the search for and acquisition of reserves and in the gathering and marketing of oil and gas production. Our competitors include national oil companies, major integrated oil and gas companies, independent oil and gas companies, individual producers, gas marketers, and major pipeline companies as well as participants in other industries supplying energy and fuel to consumers. Some of our competitors may have greater and more diverse resources on which to draw than we do. If we are not successful in our competition for oil and gas reserves or in our marketing of production, our financial condition and results of operations may be adversely affected.

The high cost or unavailability of drilling rigs, equipment, supplies, personnel, and other oilfield services could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget, which could have a material adverse effect on our business, financial condition, or results of operations.

Our industry is cyclical and, from time to time, there is a shortage of drilling rigs, equipment, supplies, or qualified personnel. During these periods, the costs of rigs, equipment, supplies, and personnel are substantially greater and their availability to us may be limited. Additionally, these services may not be available on commercially reasonable terms. The high cost or unavailability of drilling rigs, equipment, supplies, personnel, and other oilfield services could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget, which could have a material adverse effect on our business, financial condition, or results of operations.

Our drilling activities may not be productive.

Drilling for oil and natural gas involves numerous risks, including the risk that we will not encounter commercially productive oil or natural-gas reservoirs. Drilling operations may be curtailed, delayed, or canceled as a result of a variety of factors, including the following:

- unexpected drilling conditions
- pressure or irregularities in formations
- equipment failures or accidents
- fires, explosions, blowouts, and surface cratering
- marine risks such as capsizing, collisions, and hurricanes
- difficulty identifying and retaining qualified personnel
- title problems
- other adverse weather conditions
- shortages or delays in the delivery of equipment

Certain of our future drilling activities may not be successful and, if unsuccessful, this failure could have an adverse effect on our future results of operations and financial condition. While all drilling, whether developmental or exploratory, involves these risks, exploratory drilling involves greater risks of dry holes or failure to find commercial quantities of hydrocarbons. Because of the percentage of our capital budget devoted to high-risk exploratory projects, it is likely that we will continue to experience significant exploration and dry hole expenses.

We have limited influence over the activities on properties we do not operate.

Other companies operate some of the properties in which we have an interest. We have limited ability to influence the operation or future development of these nonoperated properties or the amount or timing of capital expenditures that we are required to fund with respect to them. Our dependence on the operator and other working-interest owners for these projects and our limited ability to influence the operation and future development of these properties could materially adversely affect the realization of our targeted returns on capital, lead to unexpected future costs, or adversely affect the timing of activities.

Our ability to sell our oil, natural-gas, and NGLs production could be materially harmed if we fail to obtain adequate services such as transportation.

The marketability of our production depends in part on the availability, proximity, and capacity of pipeline facilities and tanker transportation. If any pipelines or tankers become unavailable, we would, to the extent possible, be required to find a suitable alternative to transport the oil, natural gas, and NGLs, which could increase our costs and/or reduce the revenues we might obtain from the sale of the oil and gas.

Our business could be negatively affected by security threats, including cybersecurity threats, and other disruptions.

As an oil and gas producer, we face various security threats, including cybersecurity threats such as attempts to gain unauthorized access to sensitive information or to render data or systems unusable; threats to the security of our facilities and infrastructure or those of third parties such as processing plants and pipelines; and threats from terrorist acts. Our implementation of various procedures and controls to monitor and mitigate security threats and to increase security for our information, facilities, and infrastructure may result in increased costs. Moreover, there can be no assurance that such procedures and controls will be sufficient to prevent security breaches from occurring. Cybersecurity attacks in particular are becoming more sophisticated and include, but are not limited to, malicious software, attempts to gain unauthorized access to data and systems, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information, and corruption of data, which could have an adverse effect on our reputation, financial condition, results of operations, or cash flows.

While we have experienced cybersecurity attacks, we have not suffered any material losses relating to such attacks; however, there is no assurance that we will not suffer such losses in the future. In addition, as cybersecurity threats continue to evolve, we may be required to expend additional resources to continue to modify or enhance our protective measures or to investigate or remediate any cybersecurity vulnerabilities.

Provisions in our corporate documents and Delaware law could delay or prevent a change of control of Anadarko, even if that change would be beneficial to our stockholders.

Our restated certificate of incorporation and by-laws contain provisions that may make a change of control of Anadarko difficult, even if it may be beneficial to our stockholders, including provisions governing the nomination and removal of directors, the prohibition of stockholder action by written consent and regulation of stockholders' ability to bring matters for action before annual stockholder meetings, and the authorization given to our Board of Directors to issue and set the terms of preferred stock.

In addition, Section 203 of the Delaware General Corporation Law imposes restrictions on mergers and other business combinations between us and any holder of 15% or more of our outstanding common stock.

We may reduce or cease to pay dividends on our common stock.

We can provide no assurance that we will continue to pay dividends at the current rate or at all. In response to the current commodity-price environment, the Company decreased the quarterly dividend from $0.27 per share to $0.05 per share in February 2016. The amount of cash dividends, if any, to be paid in the future is determined by our Board of Directors based on our financial condition, results of operations, cash flows, levels of capital and exploration expenditures, future business prospects, expected liquidity needs, and other matters that our Board of Directors deems relevant.

The loss of key members of our management team, or difficulty attracting and retaining experienced technical personnel, could reduce our competitiveness and prospects for future success.

The successful implementation of our strategies and handling of other issues integral to our future success will depend, in part, on our experienced management team. The loss of key members of our management team could have an adverse effect on our business. We do not carry key man insurance. Our exploratory drilling success and the success of other activities integral to our operations will depend, in part, on our ability to attract and retain experienced explorationists, engineers, and other professionals. Competition for such professionals could be intense. If we cannot retain our technical personnel or attract additional experienced technical personnel, our ability to compete could be harmed.

Item 1B. Unresolved Staff Comments

None.

Item 3. Legal Proceedings

The Company is a defendant in a number of lawsuits and is involved in governmental proceedings and regulatory controls arising in the ordinary course of business, including personal injury and death claims; title disputes; tax disputes; royalty claims; contract claims; contamination claims relating to oil and gas exploration, development, production, transportation, and processing; and environmental claims, including claims involving assets owned by acquired companies and claims involving assets previously sold to third parties and no longer a part of the Company's current operations. Anadarko is also subject to various environmental-remediation and reclamation obligations arising from federal, state, tribal, and local laws and regulations. While the ultimate outcome and impact on the Company cannot be predicted with certainty, after consideration of recorded expense and liability accruals, management believes that the resolution of pending proceedings will not have a material adverse effect on the Company's financial condition, results of operations, or cash flows.

WGR Operating, LP, a wholly owned subsidiary of the Company, is currently in negotiations with the EPA with respect to alleged noncompliance with the leak detection and repair requirements of the Clean Air Act at its Granger, Wyoming facilities. Although management cannot predict the outcome of settlement discussions, it is likely a resolution of this matter will result in a fine or penalty in excess of $100,000.

See *Note 15—Contingencies* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K, which is incorporated herein by reference, for a discussion of material legal proceedings to which the Company is a party.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

MARKET INFORMATION, HOLDERS, AND DIVIDENDS

At January 29, 2016, there were approximately 10,870 holders of record of Anadarko common stock. The common stock of Anadarko is traded on the New York Stock Exchange. The following shows information regarding the market price of, and dividends declared and paid on, the Company's common stock by quarter for 2015 and 2014:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2015				
Market Price				
High	**$ 90.10**	**$ 95.94**	**$ 78.70**	**$ 73.87**
Low	**$ 73.82**	**$ 77.75**	**$ 58.10**	**$ 44.50**
Dividends	**$ 0.27**	**$ 0.27**	**$ 0.27**	**$ 0.27**
2014				
Market Price				
High	$ 86.86	$ 112.06	$ 113.51	$ 102.68
Low	$ 77.80	$ 84.54	$ 100.40	$ 71.00
Dividends	$ 0.18	$ 0.27	$ 0.27	$ 0.27

The amount of future common stock dividends will depend on earnings, financial condition, capital requirements, the effect a dividend payment would have on the Company's compliance with its financial covenants, and other factors, and will be determined by the Board of Directors on a quarterly basis. For additional information, see *Liquidity and Capital Resources—Financing Activities—Common Stock Dividends* and *Distributions to Noncontrolling Interest Owners* under Item 7 of this Form 10-K.

SECURITIES AUTHORIZED FOR ISSUANCE UNDER EQUITY COMPENSATION PLANS

The following sets forth information with respect to the equity compensation plans available to directors, officers, and employees of the Company at December 31, 2015:

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants, and rights	(b) Weighted-average exercise price of outstanding options, warrants, and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column(a))
Equity compensation plans approved by security holders	7,046,098	$ 71.86	16,378,707
Equity compensation plans not approved by security holders	—	—	—
Total	7,046,098	$ 71.86	16,378,707

PURCHASES OF EQUITY SECURITIES BY THE ISSUER AND AFFILIATED PERSONS

The following sets forth information with respect to repurchases made by the Company of its shares of common stock during the fourth quarter of 2015:

Period	Total number of shares purchased [(1)]	Average price paid per share	Total number of shares purchased as part of publicly announced plans or programs	Approximate dollar value of shares that may yet be purchased under the plans or programs
October 1-31, 2015	186,340	$ 70.32	—	
November 1-30, 2015	63,867	$ 69.09	—	
December 1-31, 2015	1,903	$ 56.61	—	
Total	252,110	$ 69.90	—	$ —

(1) During the fourth quarter of 2015, all purchased shares related to stock received by the Company for the payment of withholding taxes due on employee stock plan share issuances.

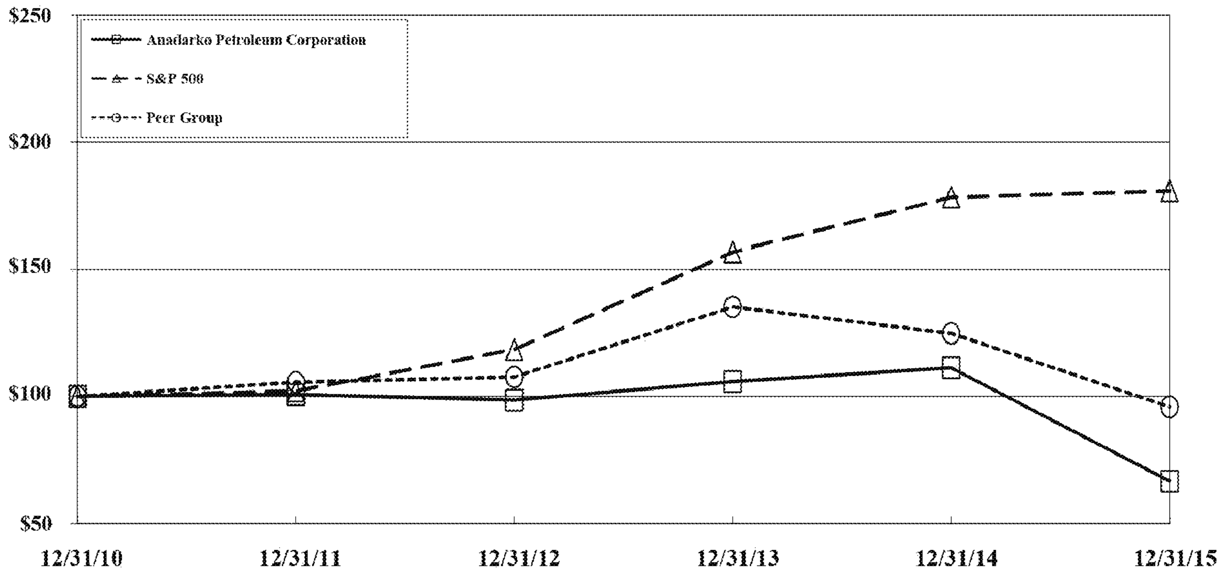
For additional information, see *Note 19—Share-Based Compensation* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

PERFORMANCE GRAPH

The following performance graph and related information shall not be deemed "soliciting material" or to be "filed" with the SEC, nor shall information be incorporated by reference into any future filing under the Securities Act of 1933 or Securities Exchange Act of 1934, each as amended, except to the extent that the Company specifically incorporates it by reference into such filing.

The following graph compares the cumulative five-year total return to stockholders of Anadarko's common stock relative to the cumulative total returns of the S&P 500 index and a peer group of 11 companies. The companies included in the peer group are Apache Corporation; Chevron Corporation; ConocoPhillips; Devon Energy Corporation; EOG Resources, Inc.; Hess Corporation; Marathon Oil Corporation; Murphy Oil Corporation; Noble Energy, Inc.; Occidental Petroleum Corporation; and Pioneer Natural Resources Company.

Comparison of 5-Year Cumulative Total Return Among
Anadarko Petroleum Corporation, the S&P 500 Index, and a Peer Group



An investment of $100 (with reinvestment of all dividends) is assumed to have been made in the Company's common stock, in the S&P 500 Index, and in the peer group on December 31, 2010, and its relative performance is tracked through December 31, 2015.

Fiscal Year Ended December 31	2010	2011	2012	2013	2014	**2015**
Anadarko Petroleum Corporation	$ 100.00	$ 100.70	$ 98.53	$ 105.81	$ 111.25	**$ 66.53**
S&P 500	100.00	102.11	118.45	156.82	178.29	**180.75**
Peer Group	100.00	105.57	107.65	135.30	124.85	**95.82**

Item 6. Selected Financial Data

	Summary Financial Information [1]				
millions except per-share amounts	**2015**	2014	2013	2012	2011
Sales Revenues	**$ 9,486**	$ 16,375	$ 14,867	$ 13,307	$ 13,882
Gains (Losses) on Divestitures and Other, net	**(788)**	2,095	(286)	104	85
Total Revenues and Other	**8,698**	18,470	14,581	13,411	13,967
Other Operating (Income) Expense					
Algeria Exceptional Profits Tax Settlement	**—**	—	33	(1,797)	—
Deepwater Horizon Settlement and Related Costs	**74**	97	15	18	3,930
Operating Income (Loss)	**(8,809)**	5,403	3,333	3,727	(1,870)
Tronox-related Contingent Loss	**5**	4,360	850	(250)	250
Income (Loss)	**(6,812)**	(1,563)	941	2,445	(2,568)
Net Income (Loss) Attributable to Common Stockholders	**(6,692)**	(1,750)	801	2,391	(2,649)
Per Common Share (amounts attributable to common stockholders)					
Net Income (Loss)—Basic	**$ (13.18)**	$ (3.47)	$ 1.58	$ 4.76	$ (5.32)
Net Income (Loss)—Diluted	**$ (13.18)**	$ (3.47)	$ 1.58	$ 4.74	$ (5.32)
Dividends	**$ 1.08**	$ 0.99	$ 0.54	$ 0.36	$ 0.36
Average Number of Common Shares Outstanding—Basic	**508**	506	502	500	498
Average Number of Common Shares Outstanding—Diluted	**508**	506	505	502	498
Cash Provided by (Used in) Operating Activities	**(1,877)**	8,466	8,888	8,339	2,505
Capital Expenditures	**$ 5,888**	$ 9,256	$ 8,523	$ 7,311	$ 6,553
Current Portion of Long-term Debt	**$ 33**	$ —	$ 500	$ —	$ 170
Long-term Debt [2]	**15,718**	15,092	13,065	13,269	15,060
Total Debt	**$ 15,751**	$ 15,092	$ 13,565	$ 13,269	$ 15,230
Total Stockholders' Equity	**12,819**	19,725	21,857	20,629	18,105
Total Assets [3]	**$ 46,414**	$ 60,967	$ 55,421	$ 52,261	$ 51,641
Annual Sales Volumes					
Oil and Condensate (MMBbls)	**116**	106	91	86	79
Natural Gas (Bcf)	**852**	945	968	913	852
Natural Gas Liquids (MMBbls)	**47**	44	33	30	27
Total (MMBOE) [4]	**305**	308	285	268	248
Average Daily Sales Volumes					
Oil and Condensate (MBbls/d)	**317**	292	248	233	217
Natural Gas (MMcf/d)	**2,334**	2,589	2,652	2,495	2,334
Natural Gas Liquids (MBbls/d)	**130**	119	91	83	74
Total (MBOE/d)	**836**	843	781	732	680
Proved Reserves					
Oil and Condensate Reserves (MMBbls)	**713**	929	851	767	771
Natural-gas Reserves (Tcf)	**6.0**	8.7	9.2	8.3	8.4
Natural-gas Liquids Reserves (MMBbls)	**340**	479	407	405	374
Total Proved Reserves (MMBOE)	**2,057**	2,858	2,792	2,560	2,539
Number of Employees	**5,800**	6,100	5,700	5,200	4,800

(1) Consolidated for Anadarko and its subsidiaries. Certain amounts for prior years have been reclassified to conform to the current presentation.

(2) Includes Western Gas Partners, LP debt of $2.7 billion at December 31, 2015, $2.4 billion at December 31, 2014, $1.4 billion at December 31, 2013, $1.2 billion at December 31, 2012, and $494 million at December 31, 2011.

(3) As a result of adopting Accounting Standards Update 2015-17, *Balance Sheet Classification of Deferred Taxes*, the Company reclassified other current assets of $722 million in 2014, $360 million in 2013, $328 million in 2012, and $138 million in 2011, to deferred income taxes. See *Note 1—Summary of Significant Accounting Policies* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

(4) Natural gas is converted to equivalent barrels at the rate of 6,000 cubic feet of gas per barrel.

Table of Measures

Bcf—Billion cubic feet	MMcf/d—Million cubic feet per day	Tcf—Trillion cubic feet
MMBbls—Million barrels	MBbls/d—Thousand barrels per day	
MMBOE—Million barrels of oil equivalent	MBOE/d—Thousand barrels of oil equivalent per day	

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion should be read together with the *Consolidated Financial Statements* and the *Notes to Consolidated Financial Statements*, which are included in this Form 10-K in Item 8, and the information set forth in *Risk Factors* under Item 1A. Unless the context otherwise requires, the terms "Anadarko" and "Company" refer to Anadarko Petroleum Corporation and its consolidated subsidiaries.

MISSION AND STRATEGY

Anadarko's mission is to deliver a competitive and sustainable rate of return to shareholders by developing, acquiring, and exploring for oil and natural-gas resources vital to the world's health and welfare. Anadarko employs the following strategy to achieve this mission:

- explore in high-potential, proven basins
- identify and commercialize resources
- employ a global business development approach
- ensure financial discipline and flexibility

Exploring in high-potential, proven basins worldwide provides the Company with growth opportunities. Anadarko's exploration success has created value by increasing future resource potential while providing the flexibility to mitigate risk by monetizing discoveries.

Developing a portfolio of primarily unconventional resources provides the Company a stable base of capital-efficient and predictable development opportunities that, in turn, position the Company for consistent growth at competitive rates.

Anadarko's global business development approach transfers core skills across the globe to assist in the discovery and development of world-class resources that are accretive to the Company's performance. These resources help form an optimized global portfolio where both surface and subsurface risks are actively managed.

A strong balance sheet is essential for the development of the Company's assets, and Anadarko is committed to disciplined investment in its businesses to efficiently manage commodity-price cycles. Maintaining financial discipline enables the Company to capitalize on the opportunities afforded by its global portfolio while allowing the Company to pursue new strategic growth opportunities.

OUTLOOK

During 2015, the oil and natural-gas industry experienced a significant decrease in commodity prices driven by a global supply/demand imbalance for oil and an oversupply of natural gas in the United States. The decline in commodity prices and global economic conditions have continued into 2016 and low commodity prices may exist for an extended period. The Company's revenues, operating results, cash flows from operations, capital spending, and future growth rates are highly dependent on the global commodity-price markets, which affect the value the Company receives from its sales of oil, natural-gas, and natural-gas liquids (NGLs) production. The Company's strategy in 2015 was to preserve and build value by focusing a greater percentage of its capital investment on longer-dated projects while driving cost savings and efficiencies through every aspect of its business. During 2015, the Company closed $2.0 billion of monetizations and was successful in lowering its capital expenditures by 36% and its operating expenses by 13% compared to 2014 while maintaining relatively flat production year over year.

The Company plans to continue its disciplined and focused approach in 2016 by emphasizing value over growth, enhancing operational efficiencies, reducing capital expenses, and managing its diverse asset portfolio. Management has recommended to the Board of Directors (Board) a 2016 capital budget of approximately $2.8 billion, which excludes the capital budget of Western Gas Partners, LP (WES), a publicly traded consolidated subsidiary. The $2.8 billion budget is nearly 50% lower than the Company's capital investments in 2015 and almost 70% lower than 2014.

The Company will continue to evaluate the oil and natural-gas price environments and may adjust its capital spending plans to maintain the appropriate liquidity and financial flexibility. Anadarko expects that its capital expenditures will be aligned with its cash flows from operations and targeted asset monetizations.

Liquidity As of December 31, 2015, Anadarko had $939 million of cash on hand plus $4.75 billion of borrowing capacity under its revolving credit facilities ($5.0 billion capacity, less $250 million of outstanding commercial paper notes). Substantially all of Anadarko's cash balances at December 31, 2015, were domiciled in the United States and were available to support its worldwide operations. In addition, future excess cash flows generated from the Company's international assets are available to support both its U.S. operations and corporate needs without incurring incremental U.S. income tax. In December 2015, Anadarko extended the maturity of its $3.0 billion five-year senior unsecured revolving credit facility (Five-Year Facility) to January 2021, and in January 2016, Anadarko replaced its $2.0 billion 364-day senior unsecured revolving credit facility (364-Day Facility) with a new $2.0 billion 364-day senior unsecured revolving credit facility that will mature in January 2017. The extension and renewal included no changes to covenants or pricing, and the original bank-group fully participated.

Anadarko's $1.750 billion 5.950% Senior Notes, scheduled to mature in September 2016, were classified as long-term debt on the Company's Consolidated Balance Sheet at December 31, 2015, as Anadarko intends to refinance these obligations prior to or at maturity with new long-term debt issuances or by using the Five-Year Facility.

As of December 31, 2015, Anadarko's long-term debt was rated "BBB" with a stable outlook by both Standard and Poor's (S&P) and Fitch Ratings (Fitch), and its commercial paper program was rated "A-2" by S&P and "F2" by Fitch. Anadarko's long-term debt was rated "Baa2" with a stable outlook and its commercial paper program was rated "P2" by Moody's Investors Service (Moody's) until December 16, 2015, when Moody's announced that it had placed both ratings under review for downgrade along with the ratings of 28 other U.S. exploration and production companies and their related subsidiaries. In February 2016, S&P affirmed Anadarko's "BBB" rating and changed the outlook from stable to negative. As of the time of filing this Form 10-K, neither Fitch nor Moody's had announced any change to Anadarko's credit ratings; however, the Company cannot be assured that its credit ratings will not be downgraded. Any downgrade in Anadarko's credit ratings could negatively impact its cost of capital, and a downgrade to a level that is below investment grade could also adversely affect the Company's ability to effectively execute aspects of its strategy or to raise debt in the public debt markets.

In the event of a downgrade in Anadarko's credit rating to a level that is below investment grade, the Company may be required to post collateral in the form of letters of credit or cash as financial assurance of its performance under certain contractual arrangements such as pipeline transportation contracts and oil and gas sales contracts. At December 31, 2015, there were no letters of credit or cash provided as assurance of the Company's performance under these types of contractual arrangements with respect to credit-risk-related contingent features. If Anadarko's credit ratings had been downgraded to a level below investment grade as of December 31, 2015, the collateral required to be posted under these arrangements would have been $460 million. Additionally, certain of these arrangements contain financial assurances language that may, under certain circumstances, permit the counterparties to request additional collateral. For additional information, see *Risk Factors* in Item 1A of this Form 10-K.

Furthermore, in the event of a downgrade in Anadarko's credit rating to a level that is below investment grade, the credit thresholds with Anadarko's derivative counterparties may be reduced or, in certain cases, eliminated, which may require the Company to post additional collateral in the form of letters of credit or cash. The aggregate fair value of all derivative instruments with credit-risk-related contingent features for which a net liability position existed on December 31, 2015, was $1.3 billion, net of collateral. As of December 31, 2015, $58 million was posted as cash collateral with Anadarko's derivative counterparties. For additional information, see *Note 9—Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Anadarko believes that its cash on hand, anticipated operating cash flows, and proceeds from expected asset monetizations will be sufficient to fund the Company's projected 2016 operational and capital programs. In response to the current commodity-price environment, the Board decreased the quarterly dividend from $0.27 per share to $0.05 per share in February 2016. On an annualized basis, the dividend decrease will have the effect of providing approximately $450 million of additional cash available to enhance the Company's operations and financial flexibility. Anadarko also expects to receive an $881 million tax refund in 2016 related to the income tax benefit associated with the Company's 2015 tax net operating loss carryback. Further, Anadarko enters into strategic derivative positions to reduce commodity-price risk and increase the predictability of cash flows. At December 31, 2015, derivative positions covered approximately 26% of Anadarko's anticipated oil sales volumes, 3% of its anticipated NGLs sales volumes, and 2% of its anticipated natural-gas sales volumes for 2016. These instruments had a fair value of $273 million as of December 31, 2015. See *Note 9—Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K. Anadarko believes that the actions taken to enhance the Company's liquidity position coupled with its asset portfolio and operating and financial performance provide the necessary financial flexibility to fund the Company's current and long-term operations.

Potential for Future Impairments During 2015, the Company recognized significant impairments of proved oil and gas and midstream properties and impairments of unproved oil and gas properties, primarily as a result of lower forecasted commodity prices and changes to the Company's drilling plans. At December 31, 2015, the Company's estimate of undiscounted future cash flows attributable to a certain depletion group with a net book value of approximately $2.2 billion indicated that the carrying amount was expected to be recovered; however, this depletion group may be at risk for impairment if the estimates of future cash flows decline. The Company estimates that, if this depletion group becomes impaired in a future period, the Company could recognize non-cash impairments in that period in excess of $800 million. It is also reasonably possible that prolonged low or further declines in commodity prices, further changes to the Company's drilling plans in response to lower prices, or increases in drilling or operating costs could result in other additional impairments.

Anadarko had approximately $5.4 billion of goodwill at December 31, 2015, allocated to the following reporting units: $4.9 billion to oil and gas exploration and production, $383 million to WES gathering and processing, $5 million to WES transportation, and $62 million to other gathering and processing. Goodwill is tested annually in October, and at interim periods when necessary. Although commodity prices declined during the year, as of December 31, 2015, the estimated fair value of the oil and gas reporting unit exceeded the carrying value by more than 15%, without consideration for any control premium, and the other reporting units were not at risk of impairment. However, it is reasonably possible that prolonged low or further declines in commodity prices, decreases in proved reserves, changes in exploration or development plans, significant property impairments, increases in operating or drilling costs, significant changes in regulations, or other negative changes to the economic environment in which Anadarko operates could result in a further reduction in the fair value of the reporting units and increase the potential for a future impairment of goodwill.

Proved Reserves Proved reserves are estimated based on the average beginning-of-month prices during the 12-month period for the respective year. The average prices used to compute proved reserves at December 31, 2015, were $50.28 per barrel (Bbl) for oil, $2.59 per million British thermal units (MMBtu) for gas, and $19.47 per Bbl for NGLs. Prices for oil, natural gas, and NGLs can fluctuate widely. For example, New York Mercantile Exchange (NYMEX) West Texas Intermediate oil prices have been volatile and ranged from a high of $107.26 per barrel in June 2014 to a low of $26.21 per Bbl in February 2016. Also, NYMEX Henry Hub natural-gas prices have been volatile and ranged from a high of $6.15 per MMBtu in February 2014 to a low of $1.76 per MMBtu in December 2015. If commodity prices remain below the average prices used to estimate 2015 proved reserves, the Company would expect additional negative price-related reserves revisions in 2016, which could be significant.

OVERVIEW

Significant 2015 operating and financial activities include the following:

Total Company

- Anadarko's sales volumes averaged 836 thousand barrels of oil equivalent per day (MBOE/d), which was relatively flat compared to 2014 and includes a 37 MBOE/d decrease related to divestitures.
- The Company's overall sales-volume product mix increased to 53% liquids in 2015 compared to 49% in 2014.
- Anadarko's higher-margin liquids sales volumes were 447 thousand barrels per day (MBbls/d), representing a 9% increase over 2014. This increase included a 14 MBbls/d decrease in sales volumes related to divestitures, including certain enhanced oil recovery (EOR) assets in the Rocky Mountains Region (Rockies) in 2015 and the Company's Chinese subsidiary in 2014.
- The Company closed several asset monetizations, totaling $1.4 billion, including the divestiture of certain coalbed methane properties and related midstream assets in the Rockies, certain EOR assets in the Rockies, and certain oil and gas properties and related midstream assets in East Texas.
- Anadarko paid $5.2 billion related to a settlement agreement resolving all claims asserted in the Tronox Adversary Proceeding. See *Note 15—Contingencies—Tronox Litigation* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.
- After previously finding that Anadarko, as a nonoperating investor in the Macondo well, was not culpable with respect to the Deepwater Horizon events, the Louisiana District Court found Anadarko liable for civil penalties under the Clean Water Act as a working-interest owner in the Macondo well and entered a judgment of $159.5 million in December 2015. See *Note 15—Contingencies—Deepwater Horizon Events* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

U.S. Onshore

- The Rockies sales volumes averaged 367 MBOE/d, representing a 2%, or 6 MBOE/d, increase over 2014, primarily from a 32%, or 54 MBOE/d, sales volume increase in the Wattenberg field, partially offset by lower sales volumes due to the April 2015 sale of certain EOR assets and the September 2015 sale of certain coalbed methane properties.
- The Southern and Appalachia Region sales volumes averaged 284 MBOE/d, representing a 5% decrease from 2014, primarily due to lower natural-gas sales volumes in the Marcellus shale due to voluntary curtailments and third-party infrastructure downtime, and the sale of certain U.S. onshore oil and gas properties and related midstream assets in East Texas, partially offset by higher sales volumes in the Eagleford shale.

Gulf of Mexico

- Gulf of Mexico sales volumes averaged 85 MBOE/d, representing a 2% increase over 2014, primarily due to the commencement of oil production from the Lucius development in January 2015, partially offset by a natural-gas production decline at Independence Hub (IHUB).
- The Company participated in the successful drilling of the nonoperated Yeti exploration well (37.5% working interest) in Walker Ridge Block 160, with the well successfully sidetracked to test the down-dip limits of the field.
- Anadarko's Heidelberg development project was completed and achieved first oil in January 2016.

International

- International sales volumes averaged 91 MBOE/d, which was relatively flat compared to 2014.
- The Kronos-1 deepwater prospect offshore Colombia encountered 130 to 230 net feet of natural-gas pay in the upper objective and encountered non-commercial hydrocarbons in a deeper objective.
- The Tweneboa/Enyenra/Ntomme (TEN) project in Ghana was more than 80% complete at year end 2015, with first oil expected in the third quarter of 2016.
- Anadarko wrote off suspended exploratory costs in Brazil where the Company does not expect to have substantive exploration and development activities for the foreseeable future given the current oil-price environment and other considerations.

Financial

- Anadarko's net loss attributable to common stockholders for 2015 totaled $6.7 billion, including impairments of $5.1 billion primarily related to certain U.S. onshore and Gulf of Mexico properties, impairments of exploration assets of $1.9 billion primarily associated with impairments of unproved properties and the write-off of suspended exploratory well costs in Brazil, and losses on divestitures of $1.0 billion.
- The Company's net cash used in operating activities was $1.9 billion in 2015, which included the $5.2 billion Tronox settlement payment. The Company ended 2015 with $939 million of cash on hand.
- The Company initiated a commercial paper program, which allows the issuance of a maximum of $3.0 billion of unsecured commercial paper notes.
- In December 2015, Anadarko extended the maturity of its Five-Year Facility to January 2021, and in January 2016, Anadarko replaced its 364-Day Facility with a new $2.0 billion 364-day senior unsecured revolving credit facility that will mature in January 2017.
- WES, a publicly traded consolidated subsidiary, completed a public offering of $500 million aggregate principal amount of 3.950% Senior Notes due 2025.
- Anadarko issued 9.2 million 7.50% tangible equity units (TEUs) at a stated amount of $50.00 per unit and raised net proceeds of $445 million.
- Anadarko completed a public secondary offering of 2.3 million common units in Western Gas Equity Partners, LP (WGP), a publicly traded consolidated subsidiary that owns partnership interests in WES, and raised net proceeds of $130 million.

FINANCIAL RESULTS

millions except per-share amounts	**2015**	2014	2013
Oil and condensate, natural-gas, and NGLs sales	**$ 8,260**	$ 15,169	$ 13,828
Gathering, processing, and marketing sales	**1,226**	1,206	1,039
Gains (losses) on divestitures and other, net	**(788)**	2,095	(286)
Revenues and other	**8,698**	18,470	14,581
Costs and expenses	**17,507**	13,067	11,248
Other (income) expense	**880**	5,349	1,227
Income tax expense (benefit)	**(2,877)**	1,617	1,165
Net income (loss) attributable to common stockholders	**$ (6,692)**	$ (1,750)	$ 801
Net income (loss) per common share attributable to common stockholders—diluted	**$ (13.18)**	$ (3.47)	$ 1.58
Average number of common shares outstanding—diluted	**508**	506	505

The following discussion pertains to Anadarko's results of operations, financial condition, and changes in financial condition. Any increases or decreases "for the year ended December 31, 2015," refer to the comparison of the year ended December 31, 2015, to the year ended December 31, 2014. Similarly, any increases or decreases "for the year ended December 31, 2014," refer to the comparison of the year ended December 31, 2014, to the year ended December 31, 2013. The primary factors that affect the Company's results of operations include commodity prices for oil, natural gas, and NGLs; sales volumes; the cost of finding such reserves; and operating costs.

Revenues and Sales Volumes

millions	**Oil and Condensate**	**Natural Gas**	**NGLs**	**Total**
2014 sales revenues	$ 9,748	$ 3,849	$ 1,572	$ 15,169
Changes associated with prices	**(5,189)**	**(1,462)**	**(871)**	**(7,522)**
Changes associated with sales volumes	**861**	**(380)**	**132**	**613**
2015 sales revenues	**$ 5,420**	**$ 2,007**	**$ 833**	**$ 8,260**
Increase/(decrease) vs. 2014	**(44)%**	**(48)%**	**(47)%**	**(46)%**
2013 sales revenues	$ 9,178	$ 3,388	$ 1,262	$ 13,828
Changes associated with prices	(1,046)	540	(86)	(592)
Changes associated with sales volumes	1,616	(79)	396	1,933
2014 sales revenues	$ 9,748	$ 3,849	$ 1,572	$ 15,169
Increase/(decrease) vs. 2013	6 %	14 %	25 %	10 %

Changes associated with sales volumes for the years ended December 31, 2015 and 2014, include decreases associated with asset divestitures.

The following provides Anadarko's sales volumes for the years ended December 31:

	2015	Inc/(Dec) vs. 2014	2014	Inc/(Dec) vs. 2013	2013
Barrels of Oil Equivalent					
(MMBOE except percentages)					
United States	**272**	(1)%	275	9%	252
International	**33**	(1)	33	2	33
Total barrels of oil equivalent	**305**	(1)	308	8	285
Barrels of Oil Equivalent per Day					
(MBOE/d except percentages)					
United States	**745**	(1)%	751	9%	691
International	**91**	(1)	92	2	90
Total barrels of oil equivalent per day	**836**	(1)	843	8	781

MMBOE—million barrels of oil equivalent

Sales volumes represent actual production volumes adjusted for changes in commodity inventories and natural-gas production volumes provided to satisfy a commitment established in conjunction with the Jubilee development plan in Ghana. Anadarko employs marketing strategies to minimize market-related shut-ins, maximize realized prices, and manage credit-risk exposure. For additional information, see *Note 9—Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K and *Other (Income) Expense—(Gains) Losses on Derivatives, net*. Production of natural gas, oil, and NGLs is usually not affected by seasonal swings in demand.

Oil and Condensate Sales Volumes, Average Prices, and Revenues

	2015	Inc/(Dec) vs. 2014	2014	Inc/(Dec) vs. 2013	2013
United States					
Sales volumes—MMBbls	**85**	14 %	74	28 %	58
MBbls/d	**232**	14	203	28	158
Price per barrel	**$ 45.00**	(49)	$ 87.99	(9)	$ 97.02
International					
Sales volumes—MMBbls	**31**	(4)%	32	(1)%	33
MBbls/d	**85**	(4)	89	(1)	90
Price per barrel	**$ 51.68**	(48)	$ 99.79	(9)	$ 109.15
Total					
Sales volumes—MMBbls	**116**	9 %	106	18 %	91
MBbls/d	**317**	9	292	18	248
Price per barrel	**$ 46.79**	(49)	$ 91.58	(10)	$ 101.41
Oil and condensate sales revenues (millions)	**$ 5,420**	(44)	$ 9,748	6	$ 9,178

MMBbls—million barrels

Oil and Condensate Sales Volumes

2015 vs. 2014 Anadarko's oil and condensate sales volumes increased by 25 MBbls/d.

- Sales volumes in the Rockies increased by 11 MBbls/d primarily in the Wattenberg field due to continued horizontal drilling, partially offset by lower sales volumes due to the sale of certain EOR assets in April 2015.
- Sales volumes in the Southern and Appalachia Region increased by 10 MBbls/d primarily in the Eagleford shale as a result of continued horizontal drilling and in the Delaware basin due to wells brought online as a result of additional infrastructure and continued drilling.
- Sales volumes in the Gulf of Mexico increased by 8 MBbls/d primarily from the Lucius development achieving first oil in January 2015, partially offset by a natural production decline at Marco Polo.
- International sales volumes decreased by 4 MBbls/d primarily due to the timing of liftings in Algeria and the sale of the Company's Chinese subsidiary in August 2014, partially offset by higher sales volumes due to the timing of liftings in Ghana.

2014 vs. 2013 Anadarko's oil and condensate sales volumes increased by 44 MBbls/d.

- Sales volumes in the Rockies increased by 33 MBbls/d primarily in the Wattenberg field due to increased horizontal drilling.
- Sales volumes in the Southern and Appalachia Region increased by 15 MBbls/d, primarily as a result of increased horizontal drilling and 2013 infrastructure expansion in the Eagleford shale and increased horizontal drilling in the Delaware basin.
- International sales volumes decreased by 1 MBbls/d primarily due to lower sales volumes in China as a result of maintenance downtime and the sale of the Company's Chinese subsidiary and the timing of liftings in Ghana, partially offset by higher sales volumes in Algeria from additional facilities and wells brought online at El Merk.
- Sales volumes in the Gulf of Mexico decreased by 1 MBbls/d primarily due to natural production declines.

Oil and Condensate Prices

2015 vs. 2014 Anadarko's average oil price received decreased primarily as a result of global oversupply.

2014 vs. 2013 Anadarko's average oil price received decreased as a result of a global oversupply and reduced oil demand resulting from continued economic weakness particularly in late 2014.

Natural-Gas Sales Volumes, Average Prices, and Revenues

	2015	Inc/(Dec) vs. 2014	2014	Inc/(Dec) vs. 2013	2013
United States					
Sales volumes—Bcf	**852**	(10)%	945	(2)%	968
MMcf/d	**2,334**	(10)	2,589	(2)	2,652
Price per Mcf	**$ 2.36**	(42)	$ 4.07	16	$ 3.50
Natural-gas sales revenues (millions)	**$ 2,007**	(48)	$ 3,849	14	$ 3,388

Bcf—billion cubic feet
MMcf/d—million cubic feet per day
Mcf—thousand cubic feet

Natural-Gas Sales Volumes

2015 vs. 2014 The Company's natural-gas sales volumes decreased by 255 MMcf/d.

- Sales volumes in the Southern and Appalachia Region decreased by 145 MMcf/d primarily due to voluntary curtailments and third-party infrastructure downtime in the Marcellus shale and the July 2015 sale of certain U.S. onshore properties and related midstream assets in East Texas. These decreases were partially offset by higher sales volumes as a result of continued horizontal drilling in the Eagleford shale.
- Sales volumes in the Rockies decreased by 66 MMcf/d primarily due to voluntary curtailments at Greater Natural Buttes, a natural production decline at Powder River basin, and the September 2015 sale of certain coalbed methane properties, partially offset by higher sales volumes in the Wattenberg field as a result of continued horizontal drilling.
- Sales volumes in the Gulf of Mexico decreased by 44 MMcf/d primarily due to a natural production decline at IHUB, partially offset by the Lucius development achieving first production in January 2015.

2014 vs. 2013 The Company's natural-gas sales volumes decreased by 63 MMcf/d.

- Sales volumes in the Rockies decreased by 90 MMcf/d primarily due to the January 2014 sale of the Company's Pinedale/Jonah assets and natural production declines in the Powder River basin and Greater Natural Buttes. These decreases were partially offset by higher sales volumes in the Wattenberg field due to increased horizontal drilling.
- Sales volumes in the Gulf of Mexico decreased by 67 MMcf/d primarily due to a natural production decline at IHUB.
- Sales volumes in the Southern and Appalachia Region increased by 94 MMcf/d primarily due to infrastructure expansions that allowed the Company to bring wells online in the Marcellus and Eagleford shales as well as continued horizontal drilling in the liquids-rich East Texas/North Louisiana horizontal development.

Natural-Gas Prices

2015 vs. 2014 The average natural-gas price Anadarko received decreased primarily due to strong year-over-year production growth in the northeast United States and slightly lower weather-driven residential and commercial demand mainly in the first half of 2015.

2014 vs. 2013 The average natural-gas price Anadarko received increased primarily due to low industry natural-gas storage levels as a result of colder than average winter temperatures and the associated high residential heating demand in early 2014. In addition, natural-gas prices increased as a result of higher industrial natural-gas demand, reduced natural-gas imports from Canada, and continued strength in exports to Mexico.

Natural-Gas Liquids Sales Volumes, Average Prices, and Revenues

	2015	Inc/(Dec) vs. 2014	2014	Inc/(Dec) vs. 2013	2013
United States					
Sales volumes—MMBbls	**45**	6%	43	28%	33
MBbls/d	**124**	6	116	28	91
Price per barrel	**$ 17.03**	(52)	$ 35.48	(7)	$ 37.97
International					
Sales volumes—MMBbls	**2**	91%	1	NM	—
MBbls/d	**6**	91	3	NM	—
Price per barrel	**$ 29.85**	(47)	$ 56.16	NM	$ —
Total					
Sales volumes—MMBbls	**47**	8%	44	31%	33
MBbls/d	**130**	8	119	31	91
Price per barrel	**$ 17.61**	(51)	$ 36.01	(5)	$ 37.97
Natural-gas liquids sales revenues (millions)	**$ 833**	(47)	$ 1,572	25	$ 1,262

NM—not meaningful

NGLs Sales Volumes

NGLs sales represent revenues from the sale of products derived from the processing of Anadarko's natural-gas production.

2015 vs. 2014 The Company's NGLs sales volumes increased by 11 MBbls/d.

- Sales volumes in the Rockies increased by 6 MBbls/d primarily in the Wattenberg field due to continued horizontal drilling and the Lancaster plant coming online in April 2014, partially offset by ethane rejection.
- International sales volumes increased by 3 MBbls/d as volumes increased in Algeria since the commencement of sales at the Company's El Merk facility during 2014.

2014 vs. 2013 The Company's NGLs sales volumes increased by 28 MBbls/d.

- Sales volumes in the Rockies increased by 16 MBbls/d primarily in the Wattenberg field due to increased horizontal drilling and the Lancaster plant coming online in April 2014.
- Sales volumes in the Southern and Appalachia Region increased by 10 MBbls/d primarily as a result of increased horizontal drilling and 2013 infrastructure expansion in the Eagleford shale.
- International sales volumes increased by 3 MBbls/d due to the commencement of sales at the Company's El Merk facility in Algeria in 2014.

NGLs Prices

2015 vs. 2014 Anadarko's average NGLs price received decreased primarily due to decreased propane prices as a result of lower seasonal demand, higher NGLs production levels, and a related decline in oil prices.

2014 vs. 2013 Anadarko's average NGLs price received decreased primarily due to lower prices for butanes and natural gasoline resulting from higher industry production levels and a related decline in oil prices.

Gathering, Processing, and Marketing

millions except percentages	**2015**	Inc/(Dec) vs. 2014	2014	Inc/(Dec) vs. 2013	2013
Gathering, processing, and marketing sales	**$ 1,226**	2%	$ 1,206	16%	$ 1,039
Gathering, processing, and marketing expense	**1,054**	2	1,030	19	869
Total gathering, processing, and marketing, net	**$ 172**	(2)	$ 176	4	$ 170

Gathering and processing sales includes revenue from the sale of NGLs and remaining residue gas extracted from natural gas purchased from third parties and processed by Anadarko as well as fee revenue earned by providing gathering, processing, compression, and treating services to third parties. Marketing sales include the margin earned from purchasing and selling third-party oil and natural gas. Gathering, processing, and marketing expense includes the cost of third-party natural gas purchased and processed by Anadarko as well as other operating and transportation expenses related to the Company's costs to perform gathering, processing, and marketing activities.

2015 vs. 2014 Gathering, processing, and marketing, net decreased by $4 million. The decrease primarily resulted from lower processing revenues due to decreased commodity prices, partially offset by increased processing volumes related to the November 2014 acquisition of Nuevo Midstream, LLC and higher marketing margins.

2014 vs. 2013 Gathering, processing, and marketing, net increased by $6 million primarily due to higher gathering and processing revenue associated with higher volumes, increased natural-gas prices, and increased infrastructure, partially offset by higher processing and transportation expenses due to the increased volumes.

Gains (Losses) on Divestitures and Other, net

millions except percentages	**2015**	Inc/(Dec) vs. 2014	2014	Inc/(Dec) vs. 2013	2013
Gains (losses) on divestitures	**$ (1,022)**	(154)%	$ 1,891	NM	$ (470)
Other	**234**	15	204	11%	184
Total gains (losses) on divestitures and other, net	**$ (788)**	(138)	$ 2,095	NM	$ (286)

Gains (losses) on divestitures and other, net includes gains (losses) on divestitures and other operating revenues, including hard-minerals royalties, earnings from equity investments, and other revenues.

2015

- The Company recognized a loss of $538 million associated with the divestiture of certain coalbed methane properties and related midstream assets in the Rockies for net proceeds of $154 million after closing adjustments.
- The Company recognized a loss of $350 million associated with the divestiture of certain EOR assets in the Rockies, with a sales price of $703 million, for net proceeds of $675 million after closing adjustments.
- The Company recognized a loss of $110 million associated with the divestiture of certain oil and gas properties and related midstream assets in East Texas, with a sales price of $440 million, for net proceeds of $425 million after closing adjustments.
- The Company recognized income of $130 million related to the settlement of a royalty lawsuit associated with a property in the Gulf of Mexico.

2014

- The Company recognized a gain of $1.5 billion related to its divestiture of a 10% working interest in Offshore Area 1 in Mozambique for net proceeds of $2.64 billion.
- The Company recognized a gain of $510 million associated with the divestiture of its Chinese subsidiary for net proceeds of $1.075 billion.
- The Company recognized a gain of $237 million associated with the divestiture of its interest in the nonoperated Vito deepwater development, along with several surrounding exploration blocks in the Gulf of Mexico, for net proceeds of $500 million.
- During the fourth quarter of 2014, Anadarko considered certain EOR assets in the Rockies to be held for sale and recognized a $456 million loss. At December 31, 2014, these assets were no longer considered held for sale as the volatility in the current commodity-price environment reduced the probability that these assets would be sold within the next year.

2013

- The Company recognized losses on assets held for sale of $704 million, primarily associated with the Pinedale/Jonah assets in Wyoming, which were sold in January 2014 for net proceeds of $581 million.
- The Company divested its interest in a soda ash joint venture for net proceeds of $310 million and recognized a gain of $140 million while retaining its royalty interest in soda ash mined by the joint venture from the Company's Land Grant. Additional consideration may also be received based on future revenue of the joint venture.
- The Company recognized gains on divestitures of $94 million for certain U.S. oil and gas properties.

See *Note 3—Acquisitions, Divestitures, and Assets Held for Sale* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for additional information on assets held for sale.

Costs and Expenses

	2015	Inc/(Dec) vs. 2014	2014	Inc/(Dec) vs. 2013	2013
Oil and gas operating (millions)	**$ 1,014**	(13)%	$ 1,171	7%	$ 1,092
Oil and gas operating—per BOE	**3.32**	(13)	3.81	(1)	3.83
Oil and gas transportation (millions)	**1,117**	—	1,116	14	981
Oil and gas transportation—per BOE	**3.66**	1	3.63	6	3.44

BOE—barrels of oil equivalent

Oil and Gas Operating Expenses

2015 vs. 2014 Oil and gas operating expenses decreased by $157 million primarily due to lower expenses of $73 million as a result of divestitures, lower workover costs of $49 million as a result of reduced activity primarily in the Rockies and the Southern and Appalachia Region, and lower surface maintenance expenses of $21 million primarily in the Rockies. The related costs per BOE decreased by $0.49 as a result of lower costs.

2014 vs. 2013 Oil and gas operating expenses increased by $79 million primarily due to higher costs associated with increased sales volumes in the Rockies and the Southern and Appalachia Region and increased activity in the Gulf of Mexico. These increases were partially offset by lower expenses due to the sales of the Company's Pinedale/Jonah assets and its Chinese subsidiary. The related costs per BOE decreased by $0.02 due to increased sales volumes, partially offset by the higher costs.

Oil and Gas Transportation Expenses

2015 vs. 2014 Oil and gas transportation expenses were relatively flat. Oil and gas transportation expenses per BOE increased by $0.03 primarily due to decreased sales volumes.

2014 vs. 2013 Oil and gas transportation expenses increased by $135 million primarily due to higher gas-gathering and transportation costs primarily attributable to higher volumes related to the growth in the Company's U.S. onshore asset base. Oil and gas transportation expenses per BOE increased by $0.19 with the higher costs partially offset by increased sales volumes.

millions	**2015**	2014	2013
Exploration Expense			
Dry hole expense	**$ 1,052**	$ 762	$ 556
Impairments of unproved properties	**1,215**	483	308
Geological and geophysical expense	**168**	168	208
Exploration overhead and other	**209**	226	257
Total exploration expense	**$ 2,644**	$ 1,639	$ 1,329

2015 vs. 2014 Exploration expense increased by $1.0 billion.

Dry hole expense increased by $290 million.

- The Company wrote off suspended exploratory well costs of $746 million in 2015, primarily related to Brazil where the Company does not expect to have substantive exploration and development activities for the foreseeable future given the current oil-price environment and other considerations.
- The Company recognized $306 million due to unsuccessful drilling activities expensed in 2015 primarily in Colombia and the Gulf of Mexico.
- Anadarko recognized $762 million due to unsuccessful drilling activities expensed in 2014 associated with wells in the Gulf of Mexico, the Rockies, and Mozambique.

Impairments of unproved properties increased by $732 million.

- In 2015, the Company recognized a $935 million impairment of unproved Greater Natural Buttes properties and a $66 million impairment of an unproved Gulf of Mexico property as a result of lower commodity prices.
- Also in 2015, the Company recognized a $109 million impairment of unproved Utica properties resulting from an assignment of mineral interests in settlement of a legal matter.
- In 2014, the Company recognized impairments of $302 million primarily related to lower oil prices, a reduction of reserves, and the expiration of certain leases in the Gulf of Mexico.
- Also in 2014, the Company recognized impairments of $50 million due to the decision not to pursue further drilling in Sierra Leone.
- The Company recognized impairments of $38 million in 2014 as a result of changes in the Company's drilling plans for certain U.S. onshore oil and gas properties.

2014 vs. 2013 Exploration expense increased by $310 million.

Dry hole expense increased by $206 million.

- The Company recognized $762 million due to unsuccessful drilling activities expensed in 2014 associated with wells in the Gulf of Mexico, the Rockies, and Mozambique.
- The Company recognized $556 million due to unsuccessful drilling activities expensed in 2013 associated with wells in Kenya, Sierra Leone, and Côte d'Ivoire.

Impairments of unproved properties increased by $175 million.

- In 2014, the Company recognized impairments of $390 million in the Gulf of Mexico, Sierra Leone, and certain U.S. onshore oil and gas properties discussed above.
- In 2013, the Company recognized impairments of $89 million in China, $53 million in Brazil, and $53 million for a U.S. onshore property as a result of changes in the Company's drilling plans.

Geological and geophysical expense decreased by $40 million due to lower seismic purchases in the Gulf of Mexico during 2014.

millions except percentages	**2015**	Inc/(Dec) vs. 2014	2014	Inc/(Dec) vs. 2013	2013
General and administrative	**$ 1,176**	(11)%	$ 1,316	21%	$ 1,090
Depreciation, depletion, and amortization	**4,603**	1	4,550	16	3,927
Other taxes	**553**	(56)	1,244	16	1,077
Impairments	**5,075**	NM	836	5	794
Other operating expense	**271**	64	165	85	89

General and Administrative Expenses (G&A)

2015 vs. 2014 G&A expense decreased by $140 million primarily due to lower bonus plan expense and lower legal fees, partially offset by increased benefit plan expense.

2014 vs. 2013 G&A expense increased by $226 million primarily due to higher employee-related expenses of $152 million primarily associated with increased headcount and higher bonus plan expense. In addition, G&A expense increased due to higher legal expenses of $38 million primarily related to the third-party reimbursement of legal expenses associated with the Algeria exceptional profits tax settlement received in 2013 and legal fees related to Tronox as well as higher consulting fees of $15 million.

Depreciation, Depletion, and Amortization (DD&A)

2015 vs. 2014 DD&A expense increased by $53 million primarily due to costs associated with additional gathering and processing facilities and higher costs and sales volumes associated with Gulf of Mexico and U.S. onshore properties. These increases were partially offset by the impact of lower costs primarily due to the impairment of the Company's Greater Natural Buttes oil and gas properties and lower expense related to revisions to asset retirement cost estimates for fully depreciated Gulf of Mexico wells.

2014 vs. 2013 DD&A expense increased by $623 million primarily due to higher sales volumes in 2014, increased asset retirement costs for wells in the Gulf of Mexico, and increased costs associated with additional gathering and processing facilities.

Other Taxes

2015 vs. 2014 Other taxes decreased by $691 million.

- U.S. severance taxes decreased by $272 million, Algerian exceptional profits taxes decreased by $238 million, and ad valorem taxes decreased by $155 million. These decreases were primarily due to lower commodity prices.
- Chinese windfall profits tax decreased by $24 million as a result of the sale of the Company's Chinese subsidiary in August 2014.

2014 vs. 2013 Other taxes increased by $167 million.

- Algerian exceptional profits taxes increased by $128 million attributable to higher oil sales volumes and the commencement of NGLs sales in 2014.
- U.S. onshore ad valorem taxes increased by $85 million attributable to increased activity related to U.S. onshore properties.
- Chinese windfall profits tax decreased by $47 million resulting from maintenance downtime in the first half of 2014 and the sale of the Company's Chinese subsidiary in August 2014.

Impairments

2015

- The Company recognized impairments of $3.0 billion related to the Company's Greater Natural Buttes oil and gas properties and $482 million for related midstream properties in the Rockies, $687 million for other U.S. onshore oil and gas properties primarily in the Southern and Appalachia Region, $557 million for other midstream properties primarily in the Rockies, and $349 million for oil and gas properties in the Gulf of Mexico, all due to lower forecasted commodity prices.

Prolonged low or further declines in commodity prices, changes to the Company's drilling plans in response to lower prices, increases in drilling or operating costs, or negative reserves revisions could result in additional impairments in future periods. See *Note 5—Impairments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for additional information on impairments and *Risk Factors* under Item 1A of this Form 10-K for further discussion on the risks associated with oil, natural-gas, and NGLs prices.

2014

- The Company recognized impairments of $545 million related to certain U.S. onshore oil and gas properties and $276 million related to certain oil and gas properties in the Gulf of Mexico that were impaired primarily due to lower forecasted commodity prices.

2013

- The Company recognized impairments of $562 million due to a reduction in estimated future net cash flows and downward revisions of reserves for certain Gulf of Mexico properties resulting from changes to the Company's development plans.
- The Company recognized impairments of $142 million for certain U.S. onshore oil and gas properties and $49 million for related midstream assets due to downward revisions of reserves resulting from changes to the Company's development plans.
- The Company recognized impairments of $30 million for certain midstream properties due to a reduction in estimated future cash flows.

Other Operating Expense

2015 vs. 2014 Other operating expense increased by $106 million primarily due to an increase in legal accruals of $97 million and a $48 million expense in 2015 for the early termination of a drilling rig, partially offset by lower payments to surface owners of $20 million.

2014 vs. 2013 Other operating expense increased by $76 million primarily due to an increase in legal accruals of $49 million and $14 million of expenses in 2014 for the early termination of drilling rigs.

Other (Income) Expense

millions	**2015**	2014	2013
Interest Expense			
Current debt, long-term debt, and other	**$ 989**	$ 973	$ 949
Capitalized interest	**(164)**	(201)	(263)
Total interest expense	**$ 825**	$ 772	$ 686

2015 vs. 2014 Interest expense increased by $53 million.

- Interest expense on debt increased by $16 million primarily due to higher debt outstanding during 2015, partially offset by decreased debt amortization costs for the $5.0 billion senior secured revolving credit facility ($5.0 billion Facility) that was replaced in January 2015.
- Capitalized interest decreased by $37 million primarily due to the completion of the Lucius development and lower construction-in-progress balances for long-term capital projects in Brazil, partially offset by higher construction-in-progress balances for long-term capital projects primarily in Ghana.

2014 vs. 2013 Interest expense increased by $86 million.

- Interest expense increased $13 million due to increased long-term debt outstanding during 2014.
- Capitalized interest decreased by $62 million primarily due to lower construction-in-progress balances for the Mozambique liquefied natural gas project and the completion of certain U.S. pipeline projects in late 2013 and early 2014.

millions	**2015**	2014	2013
(Gains) Losses on Derivatives, net			
(Gains) losses on commodity derivatives, net	**$ (367)**	$ (589)	$ 141
(Gains) losses on interest-rate and other derivatives, net	**268**	786	(539)
Total (gains) losses on derivatives, net	**$ (99)**	$ 197	$ (398)

(Gains) losses on derivatives, net represents the changes in fair value of the Company's derivative instruments as a result of changes in commodity prices and interest rates as well as contract modifications. Anadarko enters into commodity derivatives to manage the risk of changes in the market prices for its anticipated sales of production. In addition, Anadarko also enters into interest-rate swaps to fix or float interest rates on existing or anticipated indebtedness to manage exposure to interest-rate changes. For additional information, see *Note 9—Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

millions	**2015**	2014	2013
Other (Income) Expense, net			
Interest income	**$ (13)**	$ (26)	$ (19)
Other	**162**	46	108
Total other (income) expense, net	**$ 149**	$ 20	$ 89

2015 vs. 2014 Other expense, net increased by $129 million.

- Losses associated with certain equity investments increased by $61 million as a result of lower commodity prices.
- Unfavorable changes in foreign currency gains/losses of $35 million were primarily associated with foreign currency held in escrow pending final determination of the Company's Brazilian tax liability attributable to the 2008 divestiture of the Peregrino field offshore Brazil.
- Environmental reserve accruals associated with properties previously acquired by Anadarko increased by $22 million.
- Interest income from short-term investments decreased by $13 million.

2014 vs. 2013 Other expense, net decreased by $69 million.

- In 2013, as a result of a Chapter 11 bankruptcy declaration by a third party, the U.S. Department of the Interior ordered Anadarko to perform the decommissioning of a production facility and related wells, which were previously sold to the third party. The Company accrued costs of $117 million during 2013 to decommission the production facility and related wells and recognized a $22 million increase in the estimated decommissioning costs in 2014. Anadarko has completed the decommissioning of the facility and expects to complete the remaining decommissioning of the wells in 2016.
- As a result of a prior acquisition, the Company recognized a restoration liability of $50 million in 2013 with respect to a landfill located in California for which the Company was notified that it is a potentially responsible party.
- The Company reversed the $56 million tax indemnification liability associated with the 2006 sale of the Company's Canadian subsidiary in 2013. The indemnity was reversed as a result of certain changes to Canadian tax laws.

millions	**2015**	2014	2013
Tronox-related contingent loss	**$ 5**	$ 4,360	$ 850

In April 2014, Anadarko and Kerr-McGee Corporation and certain of its subsidiaries (collectively, Kerr-McGee) entered into a settlement agreement for $5.15 billion, resolving all claims asserted in the Tronox Adversary Proceeding. This amount represents principal of approximately $3.98 billion plus 6% interest from the filing of the Adversary Proceeding on May 12, 2009, through April 3, 2014. In addition, the Company agreed to pay interest on that amount from April 3, 2014, through the payment of the settlement. In January 2015, the Company paid $5.2 billion after the settlement became effective. See *Note 15—Contingencies—Tronox Litigation* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Income Tax Expense

millions except percentages	**2015**	2014	2013
Income tax expense (benefit)	**$ (2,877)**	$ 1,617	$ 1,165
Income (loss) before income taxes	**(9,689)**	54	2,106
Effective tax rate	**30%**	2,994%	55%

The Company reported a loss before income taxes for the year ended December 31, 2015. As a result, items that ordinarily increase or decrease the tax rate will have the opposite effect. The decrease from the 35% U.S. federal statutory rate for the year ended December 31, 2015, was primarily attributable to the following:

- tax impact from foreign operations
- non-deductible Algerian exceptional profits tax for Algerian income tax purposes
- net changes in uncertain tax positions
- dispositions of non-deductible goodwill

The increase from the 35% U.S. federal statutory rate for the year ended December 31, 2014, was primarily attributable to the following:

- net changes in uncertain tax positions related to the settlement agreement associated with the Tronox Adversary Proceeding
- net changes in other uncertain tax positions
- non-deductible Algerian exceptional profits tax for Algerian income tax purposes
- tax impact from foreign operations

The increase from the 35% U.S. federal statutory rate for the year ended December 31, 2013, was primarily attributable to the following:

- tax impact from foreign operations
- non-deductible Algerian exceptional profits tax for Algerian income tax purposes
- deferred tax adjustments

For additional information on income tax rates, see *Note 12—Income Taxes* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Net Income (Loss) Attributable to Noncontrolling Interests

millions except percentages	**2015**	2014	2013
Net income (loss) attributable to noncontrolling interests	**$ (120)**	$ 187	$ 140
Public ownership in WES, limited partnership interest	**55.1%**	55.0%	56.4%
Public ownership in WGP, limited partnership interest	**12.7%**	11.7%	9.0%

The net loss attributable to noncontrolling interests for 2015 was primarily a result of WES midstream asset impairments of $514 million due to a reduction in estimated future cash flows caused by the low commodity-price environment and resulting reduced producer drilling activity and related throughput. See *Note 20—Noncontrolling Interests* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

LIQUIDITY AND CAPITAL RESOURCES

millions except percentages	**2015**	2014	2013
Net cash provided by (used in) operating activities	**$ (1,877)**	$ 8,466	$ 8,888
Net cash provided by (used in) investing activities	**(4,771)**	(6,472)	(8,216)
Net cash provided by (used in) financing activities	**220**	1,675	623
Total debt	**15,751**	15,092	13,565
Total equity	**15,457**	22,318	23,650
Debt to total capitalization ratio	**50.5%**	40.3%	36.5%

Overview Anadarko believes that its cash on hand, anticipated operating cash flows, proceeds from expected asset monetizations, and available borrowing capacity will be sufficient to fund the Company's projected 2016 operational and capital programs and continue to meet its other current obligations. The Company continuously monitors its liquidity needs, coordinates its capital expenditure program with its expected cash flows and projected debt-repayment schedule, and evaluates available funding alternatives in light of current and expected conditions. The Company has a variety of funding sources available, including cash on hand, an asset portfolio that provides ongoing cash-flow-generating capacity, opportunities for liquidity enhancement through divestitures and joint-venture arrangements that reduce future capital expenditures, and the Company's credit facilities and commercial paper program. In addition, an effective registration statement is available to Anadarko covering the sale of WGP common units owned by the Company.

Operating Activities

One of the primary sources of variability in the Company's cash flows from operating activities is the fluctuation in commodity prices, the impact of which Anadarko partially mitigates by entering into commodity derivatives. Sales volume changes also impact cash flow, but historically have not been as volatile as commodity prices. Anadarko's cash flows from operating activities are also impacted by the costs related to continued operations and debt service.

Anadarko's cash flow used in operating activities in 2015 was $1.9 billion, compared to cash flows provided by operating activities of $8.5 billion in 2014 and $8.9 billion in 2013. The decrease in 2015 was primarily due to the $5.2 billion Tronox settlement payment, decreased sales revenues primarily resulting from lower commodity prices, and a net decrease in accounts payable and accrued expenses.

Cash flows from operating activities for 2014 decreased due to $730 million of cash received in 2013 associated with the Algeria exceptional profits tax settlement, a $520 million income tax payment in 2014 associated with the Company's divestiture of a 10% working interest in Offshore Area 1 in Mozambique, lower average oil and NGLs prices, lower natural-gas volumes, higher operating expenses, and the unfavorable impact of changes in working capital items. These decreases were substantially offset by higher average natural-gas prices, higher sales volumes for oil and NGLs, and net cash received in settlement of commodity derivative instruments.

Tronox Settlement Payment In April 2014, Anadarko and Kerr-McGee entered into a settlement agreement to resolve all claims asserted in the Tronox Adversary Proceeding for $5.15 billion. In addition, the Company agreed to pay interest on that amount from April 3, 2014, through payment of the settlement, with an annual interest rate of 1.5% for the first 180 days and 1.5% plus the one-month LIBOR thereafter. In January 2015, the Company paid $5.2 billion after the settlement agreement became effective using cash on hand and borrowings. See *Note 15—Contingencies—Tronox Litigation* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Pension and Other Postretirement Contributions Contributions to the pension and other postretirement plans were $58 million in 2015, $136 million in 2014, and $174 million in 2013. The Company expects to contribute $46 million in 2016 to its pension and other postretirement plans.

Investing Activities

Capital Expenditures The following presents the Company's capital expenditures:

millions	**2015**	2014	2013
Cash Flows from Investing Activities			
Additions to properties and equipment and dry holes	**$ 6,067**	$ 9,508	$ 7,721
Adjustments for capital expenditures			
Changes in capital accruals	**(226)**	(237)	246
Corporate acquisitions	**—**	—	475
Other	**47**	(15)	81
Total capital expenditures [1]	**$ 5,888**	$ 9,256	$ 8,523

[1] Includes WES capital expenditures of $525 million in 2015, $696 million in 2014, and $792 million in 2013.

During 2015, cash from operations and property divestitures were the primary sources for funding capital investments. The Company's capital expenditures decreased by 36% for the year ended December 31, 2015, primarily due to reduced development and exploration activity, which resulted in decreased development costs of $2.1 billion primarily in the Rockies and the Southern and Appalachia Region; lower exploration costs of $710 million primarily in the Southern and Appalachia Region and the Gulf of Mexico; and lower gathering, processing, and other costs of $498 million primarily due to lower expenditures for plants and gathering in the Rockies. Development acquisitions in 2014 included a spar lease buyout of $110 million in the Gulf of Mexico. These decreases were partially offset by the 2015 acquisition of certain oil and gas properties in the Delaware basin for $79 million.

The Company's capital expenditures increased by 9% for the year ended December 31, 2014, due to increased development costs primarily in the Wattenberg field of $663 million and in the Eagleford shale of $546 million and a spar lease buyout of $110 million in the Gulf of Mexico. The increase in the Eagleford shale was primarily due to the 2013 development drilling being funded by a third party as a result of a carried-interest agreement that was fully funded in June 2013. These 2014 increases were partially offset by 2013 acquisitions of certain oil and gas properties and related assets in the Moxa area of Wyoming for $310 million, primarily representing the fair value of the oil and gas properties acquired, and the acquisition of a 33.75% interest in gas-gathering systems located in the Marcellus shale in north-central Pennsylvania from a third party by WES for $135 million.

Carried-Interest Arrangements In 2014, the Company entered into a carried-interest arrangement that requires a third party to fund $442 million of Anadarko's capital costs in exchange for a 34% working interest in the Eaglebine development, located in Southeast Texas. The third-party funding is expected to cover Anadarko's future capital costs in the development through 2020. At December 31, 2015, $111 million of the $442 million carry obligation had been funded.

In 2013, the Company entered into a carried-interest arrangement that requires a third party to fund $860 million of Anadarko's capital costs in exchange for a 12.75% working interest in the Heidelberg development, located in the Gulf of Mexico. At December 31, 2015, $793 million of the $860 million carry obligation had been funded.

Acquisitions of Businesses In November 2014, WES acquired Nuevo Midstream, LLC (Nuevo), which owns and operates gathering and processing assets located in the Delaware basin in West Texas, for $1.557 billion, including $30 million of cash acquired. Following the acquisition, WES changed the name of Nuevo to Delaware Basin Midstream, LLC. See *Note 3—Acquisitions, Divestitures, and Assets Held for Sale* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Divestitures Anadarko received pretax sales proceeds related to property divestiture transactions of $1.4 billion in 2015, $5.0 billion in 2014, and $567 million in 2013. See *Note 3—Acquisitions, Divestitures, and Assets Held for Sale* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Investments Capital contributions for equity investments are included in Other, net under Investing Activities in the Company's Consolidated Statement of Cash Flows. The Company made capital contributions for equity investments of $119 million in 2015 and $167 million in 2014, which were primarily associated with joint ventures for a gas processing plant, marine well containment, and pipelines. The Company made capital contributions for equity investments of $396 million in 2013, which were primarily associated with joint ventures to construct the Front Range Pipeline, the Texas Express Pipeline, and two fractionation trains in Mont Belvieu.

Financing Activities

Senior Notes The following summarizes the Company's debt activity related to senior notes:

millions	**2015**	2014	2013	**Description**
Issuances	**$ 500**	$ —	$ —	WES 3.950% Senior Notes due 2025
	—	625	—	3.450% Senior Notes due 2024
	—	625	—	4.500% Senior Notes due 2044
	—	100	250	WES 2.600% Senior Notes due 2018
	—	400	—	WES 5.450% Senior Notes due 2044
Repayments	—	(500)	—	7.625% Senior Notes due 2014
	—	(275)	—	5.750% Senior Notes due 2014

In 2015, net proceeds from the WES 3.950% Senior Notes were used to repay borrowings under WES's five-year $1.2 billion senior unsecured revolving credit facility (RCF). In 2014, net proceeds from the 3.450% Senior Notes and 4.500% Senior Notes were used for general corporate purposes and net proceeds from the WES 2.600% Senior Notes and WES 5.450% Senior Notes were used to repay WES RCF borrowings and for general partnership purposes. In 2013, net proceeds from the WES 2.600% Senior Notes were used to repay WES RCF borrowings.

Revolving Credit Facilities In June 2014, Anadarko entered into a $3.0 billion five-year senior unsecured revolving credit facility (Five-Year Facility) and a $2.0 billion 364-day senior unsecured revolving credit facility (364-Day Facility). In January 2015, upon satisfaction of certain conditions, including the payment of the settlement related to the Tronox Adversary Proceeding, these facilities replaced the Company's $5.0 billion Facility. In December 2015, the Company amended the Five-Year Facility to extend the maturity date to January 2021, and in January 2016, the Company replaced the 364-Day Facility with a new $2.0 billion 364-day senior unsecured revolving facility on identical terms that will mature in January 2017.

The following summarizes the Company's debt activity related to revolving credit facilities:

millions	**2015**	2014	2013	**Description**
Borrowings	**$ 1,800**	$ —	$ —	364-Day Facility
	1,500	—	—	$5.0 billion Facility
	400	1,160	710	WES RCF
Repayments	**(1,800)**	—	—	364-Day Facility
	(1,500)	—	—	$5.0 billion Facility
	(610)	(650)	(710)	WES RCF

Anadarko Credit Facilities During 2015, borrowings under the 364-Day Facility were primarily used to repay $1.5 billion of borrowings entered into in January 2015 under its $5.0 billion Facility, which were used for partial payment of the settlement related to the Tronox Adversary Proceeding and for general corporate purposes. At December 31, 2015, the Company had no outstanding borrowings under the Five-Year Facility or the 364-Day Facility and was in compliance with all covenants therein.

WES RCF During 2015, WES borrowings were primarily used for general partnership purposes, including the funding of capital expenditures. At December 31, 2015, WES was in compliance with all covenants contained in its RCF, had outstanding borrowings under its RCF of $300 million at an interest rate of 1.73%, had outstanding letters of credit of $6 million, and had available borrowing capacity of $894 million.

During 2014, WES borrowings were primarily used to partially fund its acquisitions of DBM and Anadarko's interests in Texas Express Pipeline LLC, Texas Express Gathering LLC, and Front Range Pipeline LLC and for other general partnership purposes, including the funding of capital expenditures. During 2013, WES borrowings were primarily used to fund the 2013 acquisitions of an interest in certain gas-gathering systems located in the Marcellus shale in north-central Pennsylvania and an intrastate pipeline in southwestern Wyoming, and for other general partnership purposes, including the funding of capital expenditures.

For additional information on the Company's revolving credit facilities, such as years of maturity, interest rates, and covenants, see *Note 11—Debt and Interest Expense* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Commercial Paper Program In January 2015, the Company initiated a commercial paper program, which allows a maximum of $3.0 billion of unsecured commercial paper notes and is supported by the Company's Five-Year Facility. The maturities of the commercial paper notes vary, but may not exceed 397 days. The commercial paper notes are sold under customary terms in the commercial paper market and are issued either at a discounted price to their principal face value or will bear interest at varying interest rates on a fixed or floating basis. Such discounted price or interest amounts are dependent on market conditions and the ratings assigned to the commercial paper program by credit rating agencies at the time of issuance of the commercial paper notes. During 2015, the Company had net borrowings of $250 million, which remained outstanding at December 31, 2015, at a weighted-average interest rate of 0.98%. During 2015, maximum outstanding borrowings under the commercial paper program were $1.4 billion and the average borrowings outstanding were $773 million with a weighted-average interest rate of 0.57%. See *Note 11—Debt and Interest Expense* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for additional information.

Debt Maturities At December 31, 2015, Anadarko's scheduled debt maturities during 2016 consisted of $1.750 billion 5.950% Senior Notes scheduled to mature in September, $250 million of borrowings under the commercial paper program, and $33 million related to the senior amortizing notes associated with the TEUs. Anadarko's Zero-Coupon Senior Notes due 2036 (Zero Coupons) can be put to the Company in October of each year, in whole or in part, for the then-accreted value, which will be $839 million at the next put date in October 2016.

The Company classified the 5.950% Senior Notes, the Zero Coupons, and the outstanding commercial paper notes as long-term debt on the Company's Consolidated Balance Sheet at December 31, 2015, as Anadarko intends to refinance these obligations prior to or at maturity with new long-term debt issuances or by using the Five-Year Facility.

Anadarko may from time to time seek to retire or purchase its outstanding debt through cash purchases and/or exchanges for other debt or equity securities in open market purchases, privately negotiated transactions, or otherwise. Such repurchases or exchanges, if any, will depend on prevailing market conditions, the Company's liquidity requirements, contractual restrictions, and other factors. The amounts involved may be material.

At December 31, 2015, Anadarko's scheduled 2017 debt maturities were $2.0 billion. For additional information on the Company's debt instruments, such as transactions during the period, years of maturity, and interest rates, see *Note 11—Debt and Interest Expense* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Tangible Equity Units During 2015, Anadarko issued 9.2 million TEUs at a stated amount of $50.00 per TEU and raised net proceeds of $445 million. Each TEU is comprised of a prepaid equity purchase contract for WGP common units, subject to Anadarko's right to elect to issue and deliver shares of Anadarko's common stock in lieu of WGP common units, and a senior amortizing note due in June 2018, which bears interest at the rate of 1.50% per year. For additional information, see *Note 10—Tangible Equity Units* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K. During 2015, Anadarko repaid $16 million of senior amortizing notes associated with the TEUs.

Derivative Instruments The Company's derivative instruments are subject to individually negotiated credit provisions that may require the Company or the counterparties to provide collateral of cash or letters of credit depending on the derivative portfolio valuation versus negotiated credit thresholds. These credit thresholds may also require full or partial collateralization or immediate settlement of the Company's obligations if certain credit-risk-related provisions are triggered such as if the Company's credit rating from major credit rating agencies declines to a level that is below investment grade. Derivative settlements and collateralization are classified as cash flows from operating activities unless the derivatives contain an other-than-insignificant financing element, in which case the settlements and collateralization are classified as cash flows from financing activities. As of December 31, 2015, the Company provided cash collateral of $58 million on its interest-rate derivatives with an other-than-insignificant financing element. For additional information, see *Note 9—Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Common Stock Dividends Anadarko paid dividends to its common stockholders of $553 million in 2015, $505 million in 2014, and $274 million in 2013. The Company increased the quarterly dividend paid to common stockholders from $0.09 per share to $0.18 per share during the third quarter of 2013 and from $0.18 per share to $0.27 per share during the second quarter of 2014. In response to the current commodity-price environment, the Company decreased the quarterly dividend to $0.05 per share in February 2016. Anadarko has paid a dividend to its common stockholders quarterly since becoming a public company in 1986.

The amount of future dividends paid to Anadarko common stockholders is determined by the Board on a quarterly basis and is based on earnings, financial conditions, capital requirements, the effect a dividend payment would have on the Company's compliance with relevant financial covenants, and other factors deemed relevant by the Board.

Equity Transactions Anadarko sold 2.3 million WGP common units to the public and raised net proceeds of $130 million in 2015, and sold approximately 6 million WGP common units to the public and raised net proceeds of $335 million in 2014. The proceeds for both periods were used for general corporate purposes.

During 2015, WES issued 874 thousand common units to the public under its continuous offering program, which allows the issuance of up to an aggregate of $500 million of WES common units, and raised net proceeds of $57 million. The remaining amount available under this program was $442 million of WES common units at December 31, 2015. During 2014, WES issued approximately 10 million common units to the public and raised net proceeds of $691 million. The proceeds were used to partially fund a portion of its DBM acquisition. WES used all the capacity to issue units under the $125 million continuous offering program as of the end of the third quarter of 2014. During 2013, WES issued approximately 12 million common units to the public, including the $125 million continuous offering program. These offerings raised net proceeds of $725 million, which were primarily used to repay outstanding RCF borrowings and for other general partnership purposes, including funding of WES's capital expenditures.

Distributions to Noncontrolling Interest Owners WES distributed to its unitholders other than Anadarko and WGP an aggregate of $231 million in 2015, $175 million in 2014, and $130 million in 2013. WES has made quarterly distributions to its unitholders since its initial public offering (IPO) in the second quarter of 2008 and has increased its distribution from $0.30 per common unit for the third quarter of 2008 to $0.80 per common unit for the fourth quarter of 2015 (paid in February 2016).

WGP distributed to its unitholders other than Anadarko an aggregate of $37 million during 2015, $24 million in 2014, and $12 million in 2013. WGP has made quarterly distributions to its unitholders since its IPO in December 2012 and has increased its distribution from $0.17875 per common unit for the first quarter of 2013 to $0.40375 per unit for the fourth quarter of 2015 (to be paid in February 2016).

Insurance Coverage and Other Indemnities

Anadarko maintains property and casualty insurance that includes coverage for physical damage to the Company's properties, blowout/control of a well, restoration and redrill, sudden and accidental pollution, third-party liability, workers' compensation and employers' liability, and other risks. Anadarko's insurance coverage includes deductibles that must be met prior to recovery. Additionally, the Company's insurance is subject to exclusions and limitations, and there is no assurance that such coverage will adequately protect the Company against liability or loss from all potential consequences and damages.

The Company's current insurance coverage includes (a) $400 million per occurrence from Oil Insurance Limited (OIL) for physical damage to Anadarko's properties on a replacement cost basis, blowout/control of well, restoration and redrill, and sudden and accidental pollution; (b) $700 million per occurrence from the commercial markets for the items described in item (a) above, which is in excess of the OIL coverage and which follows the form of OIL coverage with certain exceptions; (c) $400 million from the commercial markets, which scales to Anadarko's working interest, for third-party liabilities, including sudden and accidental pollution and aviation liability; and (d) $275 million for aircraft liability (in addition to the third-party liability limits described in item (c) above). Anadarko does not carry significant coverage for loss of production income from any of the Company's facilities or for any losses that result from the effects of a named windstorm.

The Company's service agreements, including drilling contracts, generally indemnify Anadarko for injuries and death to employees of the service provider and subcontractors hired by the service provider as well as for property damage suffered by the service provider and its contractors. Also, these service agreements generally indemnify Anadarko for pollution originating from the equipment of any contractors or subcontractors hired by the service provider.

Off-Balance-Sheet Arrangements

Anadarko may enter into off-balance-sheet arrangements and transactions that can give rise to material off-balance-sheet obligations. The Company's material off-balance-sheet arrangements and transactions include operating lease arrangements and undrawn letters of credit. In addition, the Company enters into other contractual agreements in the normal course of business for processing, treating, transportation, and storage of oil, natural gas, and NGLs as well as for other oil and gas activities as discussed below in *Obligations*. Other than the items discussed above, there are no other transactions, arrangements, or other relationships with unconsolidated entities or other persons that are reasonably likely to materially affect Anadarko's liquidity or availability of or requirements for capital resources.

Obligations

The following is a summary of the Company's obligations at December 31, 2015:

	Obligations by Period [1]				
millions	2016	2017-2018	2019-2020	2021 and beyond	Total
Total debt					
Principal—total borrowings at face value [2]	$ 2,033	$ 2,516	$ 1,200	$ 11,563	$ 17,312
Principal—capital lease obligation	—	—	1	19	20
Investee entities' debt [3]	—	—	—	2,853	2,853
Interest on borrowings	932	1,500	1,161	7,460	11,053
Interest on capital lease obligations	2	3	4	13	22
Investee entities' interest [3]	50	144	173	2,351	2,718
Operating leases					
Drilling rig commitments	739	834	215	—	1,788
Production platforms	21	43	50	23	137
Other	46	79	49	18	192
Oil and gas activities	741	886	276	314	2,217
Asset retirement obligations	309	128	304	1,318	2,059
Midstream and marketing activities	1,114	2,137	1,996	2,612	7,859
Derivative liabilities [4]	54	419	513	500	1,486
Uncertain tax positions, interest, and penalties [5]	418	65	—	1,307	1,790
Environmental liabilities	24	25	32	64	145
Other	—	116	—	—	116
Total	$ 6,483	$ 8,895	$ 5,974	$ 30,415	$ 51,767

(1) This table does not include litigation-related contingent liabilities or the Company's pension and postretirement benefit obligations. See *Note 15—Contingencies* and *Note 16—Pension Plans, Other Postretirement Benefits, and Defined-Contribution Plans* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

(2) Includes the fully accreted principal amount of the Zero Coupons of approximately $2.4 billion as coming due after 2020. While the Zero Coupons do not mature until 2036, the outstanding Zero Coupons can be put to the Company each October, in whole or in part, for the then-accreted value. The Company could be required to repurchase the outstanding Zero Coupons at $839 million in October 2016 (the next potential put date).

(3) Anadarko has legal right of setoff and intends to net-settle its obligations under each of the notes payable to the investees with the distributable value of its interest in the corresponding investee. Accordingly, the investments and the obligations are presented net on the Company's Consolidated Balance Sheets in other long-term liabilities—other for all periods presented. These notes payable provide for a variable rate of interest, reset quarterly. Therefore, future interest payments presented in the table above are estimated using the forward LIBOR rate curve. Further, the above table does not reflect the preferred return that Anadarko receives on its investment in these entities, which is also LIBOR-based, but with a lower margin than the margin on the associated notes payable. See *Note 8—Equity-Method Investments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

(4) Represents Anadarko's gross derivative liability after taking into account the impacts of netting margin and collateral balances deposited with counterparties. See *Note 9—Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

(5) See *Note 12—Income Taxes* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Operating Leases Operating lease obligations include approximately $1.7 billion related to five offshore drilling vessels and $98 million related to certain contracts for U.S. onshore drilling rigs. Anadarko manages its access to rigs to support the execution of its drilling strategy over the next several years. Lease payments associated with the drilling of exploratory wells and development wells, net of amounts billed to partners, will initially be capitalized as a component of oil and gas properties, and either depreciated or impaired in future periods or written off as exploration expense. At December 31, 2015, the Company had $329 million in various commitments under non-cancelable operating lease agreements for production platforms and equipment, buildings, facilities, compressors, and aircraft. For additional information, see *Note 14—Commitments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Oil and Gas Activities At December 31, 2015, Anadarko had various long-term contractual commitments pertaining to exploration, development, and production activities that extend beyond 2015. The Company has work-related commitments for, among other things, drilling wells, obtaining and processing seismic data, and fulfilling rig commitments. The preceding table includes long-term drilling and work-related commitments of $2.2 billion, comprised of approximately $1.5 billion related to the United States and $728 million related to international locations.

Asset Retirement Obligations Anadarko is obligated to fund the costs of disposing of long-lived assets upon their abandonment. The majority of Anadarko's asset retirement obligations (AROs) relate to the plugging of wells and the related abandonment of oil and gas properties. The Company's AROs are recorded at estimated fair value, measured by reference to the expected future cash outflows required to satisfy the retirement obligation discounted at the Company's credit-adjusted risk-free interest rate. Revisions to estimated AROs can result from changes in retirement cost estimates, revisions to estimated inflation rates, and changes in the estimated timing of abandonment.

Midstream and Marketing Activities Anadarko has entered into various processing, transportation, storage, and purchase agreements to access markets and provide flexibility to sell its oil, natural gas, and NGLs in certain areas.

Environmental Liabilities Anadarko is subject to various environmental-remediation and reclamation obligations arising from federal, state, tribal, and local laws and regulations. At December 31, 2015, the Company's Consolidated Balance Sheet included a $145 million liability for remediation and reclamation obligations. The Company continually monitors the liability recorded and ongoing remediation and reclamation activities, and believes the amount recorded is appropriate. For additional information on environmental issues, see *Risk Factors* under Item 1A of this Form 10-K.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements in accordance with generally accepted accounting principles in the United States (GAAP) requires management to make informed judgments and estimates that affect the reported amounts of assets, liabilities, revenues, and expenses. See *Note 1—Summary of Significant Accounting Policies* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for discussion of the Company's significant accounting policies. Changes in facts and circumstances or additional information may result in revised estimates, and actual results may differ from these estimates. Management considers the following to be its most critical accounting estimates that involve judgment. The selection, development, and disclosure of these estimates is discussed with the Company's Audit Committee.

Proved Reserves

Anadarko estimates its proved oil and gas reserves according to the definition of proved reserves provided by the Securities and Exchange Commission and the Financial Accounting Standards Board. This definition includes oil, natural gas, and NGLs that geological and engineering data demonstrate with reasonable certainty to be economically producible in future periods from known reservoirs under existing economic conditions, operating methods, government regulations, etc. (at prices and costs as of the date the estimates are made). Prices include consideration of price changes provided only by contractual arrangements, and do not include adjustments based on expected future conditions. For reserves information, see *Oil and Gas Properties and Activities—Proved Reserves* under Items 1 and 2 of this Form 10-K and the *Supplemental Information on Oil and Gas Exploration and Production Activities* under Item 8 of this Form 10-K.

The Company's estimates of proved reserves are made using available geological and reservoir data as well as production performance data. These estimates are reviewed annually by internal reservoir engineers and revised, either upward or downward, as warranted by additional data. Revisions are necessary due to changes in, among other things, development plans, reservoir performance, prices, economic conditions, and governmental restrictions as well as changes in the expected recovery associated with infill drilling. Decreases in prices, for example, may cause a reduction in some proved reserves due to reaching economic limits at an earlier projected date.

The quantities of estimated proved oil and gas reserves are a significant component of DD&A. A material adverse change in the estimated volumes of proved reserves could have a negative impact on DD&A and could result in property impairments. If the estimates of proved reserves used in the unit-of-production calculations had been lower by five percent across all properties, DD&A in 2015 would have increased by approximately $223 million.

Exploratory Costs

Under the successful efforts method of accounting, exploratory costs associated with a well discovering hydrocarbons are initially capitalized, or suspended, pending a determination as to whether a commercially sufficient quantity of proved reserves can be attributed to the area as a result of drilling. At the end of each quarter, management reviews the status of all suspended exploratory drilling costs in light of ongoing exploration activities, in particular, whether the Company is making sufficient progress in its ongoing exploration and appraisal efforts or, in the case of discoveries requiring government sanctioning, analyzing whether development negotiations are underway and proceeding as planned. If management determines that future appraisal drilling or development activities are unlikely to occur, associated suspended exploratory well costs are expensed. Therefore, at any point in time, the Company may have capitalized costs on its Consolidated Balance Sheets associated with exploratory wells that may be charged to exploration expense in future periods. See *Note 6—Suspended Exploratory Well Costs* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for additional information.

Fair Value

The Company estimates fair value of long-lived assets for impairment testing, reporting units for goodwill impairment testing when necessary, assets and liabilities acquired in a business combination or exchanged in non-monetary transactions, pension plan assets, and initial measurements of AROs. When the Company is required to measure fair value and there is not a market-observable price for the asset or liability or for a similar asset or liability, the Company uses the cost, income, or market valuation approaches depending on the quality of information available to support management's assumptions. The cost approach is based on management's best estimate of the current asset replacement cost. The income approach is based on management's best assumptions regarding expectations of projected cash flows, and discounts the expected cash flows using a commensurate risk-adjusted discount rate. The market approach is based on management's best assumptions regarding prices and other relevant information from market transactions involving comparable assets. Such evaluations involve significant judgment and the results are based on expected future events or conditions such as sales prices, estimates of future oil and gas production or throughput, development and operating costs and the timing thereof, future net cash flows, economic and regulatory climates, and other factors, most of which are often outside of management's control. However, assumptions used reflect a market participant's view of long-term prices, costs, and other factors, and are consistent with assumptions used in the Company's business plans and investment decisions.

Property Impairments

When circumstances indicate that proved oil and gas properties may be impaired, the expected undiscounted future net cash flows of the asset group are compared to the carrying amount of the asset. If the expected undiscounted future net cash flows, based on the Company's estimate of future oil and natural-gas prices, operating costs, anticipated production from proved reserves and other relevant data, are lower than the carrying amount, the carrying amount is reduced to fair value. Fair value estimates require significant judgment and oil and natural-gas prices are a significant component of the fair-value estimate. Prices have exhibited significant volatility in the past, and the Company expects that volatility to continue in the future.

A long-lived asset other than an unproved oil and gas property is evaluated for potential impairment whenever events or changes in circumstances indicate that its carrying value may be greater than its undiscounted future net cash flows. Impairment, if any, is measured as the excess of an asset's carrying amount over its estimated fair value. The Company uses a variety of fair-value measurement techniques as discussed above when market information for the same or similar assets does not exist.

Goodwill Impairments

The Company tests goodwill for impairment annually in October (or more frequently as circumstances dictate). The Company first assesses whether an impairment of goodwill is indicated through a qualitative assessment to determine the likelihood of whether the fair value of the reporting unit is less than its carrying amount, including goodwill. If the Company concludes it is more likely than not that fair value of the reporting unit exceeds the related carrying amount, then goodwill is not impaired and further testing is not necessary. If the qualitative assessment indicates fair value of the reporting unit may be less than its carrying amount, the Company compares the estimated fair value of the reporting unit to which goodwill is assigned to the carrying amount of the associated net assets, including goodwill, and determines whether impairment is necessary.

When evaluating whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount, the Company assesses relevant events and circumstances, including the following:

- significant changes in the stock price of Anadarko, WES, and WGP
- changes in commodity prices
- changes in cost factors such as costs of drilling; production costs; and gathering, processing, and other transportation costs
- impairments recognized by the Company
- acquisitions and disposals of assets

- changes to the Company's reserves, including changes due to fluctuations in commodity prices and updates to the Company's plans or forecasts
- changes in trading multiples for midstream peers

Because quoted market prices for the Company's reporting units are not available, management applies judgment in determining the estimated fair value of reporting units for purposes of performing goodwill impairment tests, when such tests are necessary. Management uses information available to make these fair-value estimates, including the present values of expected future cash flows using discount rates commensurate with the risks associated with the assets and observable for the oil and gas exploration and production reporting unit, control premiums and market multiples of earnings before interest, taxes, depreciation, and amortization (EBITDA) for the gathering and processing and transportation reporting units.

In estimating the fair value of its oil and gas exploration and production reporting unit, the Company assumes production profiles used in its estimation of reserves that are disclosed in the Company's supplemental oil and gas disclosures, market prices based on the forward price curve for oil and gas at the test date (adjusted for location and quality differentials), capital and operating costs consistent with pricing and expected inflation rates, and discount rates that management believes a market participant would use based upon the risks inherent in Anadarko's operations. Management also includes control premium assumptions based on observable market information regarding how a market participant would value the oil and gas exploration and production reporting unit as a whole rather than as individual properties that are part of an oil and gas portfolio.

The Company estimates fair value for the WES gathering and processing, WES transportation, and other gathering and processing reporting units by applying an estimated multiple to projected EBITDA. The Company considered observable transactions in the market and trading multiples for peers in determining an appropriate multiple to apply against the Company's projected EBITDA for these reporting units.

A lower fair-value estimate in the future for any of these reporting units could result in impairment of goodwill. Factors that could trigger a lower fair-value estimate include prolonged low or further declines in commodity prices, decreases in proved reserves, changes in exploration or development plans, significant property impairments, increases in operating or drilling costs, significant changes in regulations, or other negative changes to the economic environment in which Anadarko operates.

Environmental Obligations and Other Contingencies

Management makes judgments and estimates when it establishes liabilities for environmental remediation, litigation, and other contingent matters. Estimates of litigation-related liabilities are based on the facts and circumstances of the individual case and on information currently available to the Company. The extent of information available varies based on the status of the litigation and the Company's evaluation of the claim and legal arguments. In future periods, a number of factors could significantly change the Company's estimate of litigation-related liabilities including discovery activities; briefings filed with the relevant court; rulings from the court made pre-trial, during trial, or at the conclusion of any trial; and similar cases involving other plaintiffs and defendants that may set or change legal precedent. As events unfold throughout the litigation process, the Company evaluates the available information and may consult with third-party legal counsel to determine whether liability accruals should be established or adjusted.

Estimates of environmental liabilities are based on a variety of factors, including, but not limited to, the stage of investigation, the stage of the remedial design, evaluation of existing remediation technologies, and presently enacted laws and regulations. In future periods, a number of factors could significantly change the Company's estimate of environmental-remediation costs such as changes in laws and regulations, changes in the interpretation or administration of laws and regulations, revisions to the remedial design, unanticipated construction problems, identification of additional areas or volumes of contaminated soil and groundwater, and changes in costs of labor, equipment, and technology. Consequently, it is not possible for management to reliably estimate the amount and timing of all future expenditures that could arise related to environmental or other contingent matters and actual costs may vary significantly from the Company's estimates. The Company's in-house legal counsel and environmental personnel regularly assess contingent liabilities and, in certain circumstances, consult with third-party legal counsel or consultants to assist in the evaluation of the Company's liability for these contingencies.

Income Taxes

The amount of income taxes recorded by the Company requires interpretations of complex rules and regulations of various tax jurisdictions throughout the world. The Company has recognized deferred tax assets and liabilities for temporary differences, operating losses, and tax-credit carryforwards. The Company routinely assesses the realizability of its deferred tax assets by analyzing the reversal periods of available net operating loss carryforwards and credit carryforwards, temporary differences in tax assets and liabilities, the availability of tax planning strategies, and estimates of future taxable income and other factors. Estimates of future taxable income are based on assumptions of oil and gas reserves and selling prices that are consistent with the Company's internal business forecasts. If the Company concludes that it is more likely than not that some of the deferred tax assets will not be realized, the tax asset is reduced by a valuation allowance. The Company routinely assesses potential uncertain tax positions and, if required, establishes accruals for such amounts. The accruals for deferred tax assets and liabilities, including deferred state income tax assets and liabilities, are subject to significant judgment by management and are reviewed and adjusted routinely based on changes in facts and circumstances. Although management considers its tax accruals adequate, material changes in these accruals may occur in the future, based on the progress of ongoing tax audits, changes in legislation, and resolution of pending tax matters.

RECENT ACCOUNTING DEVELOPMENTS

See *Note 1—Summary of Significant Accounting Policies* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for discussion of recent accounting developments affecting the Company.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The Company's primary market risks are attributable to fluctuations in energy prices and interest rates. In addition, foreign-currency exchange-rate risk exists due to anticipated foreign-currency-denominated payments and receipts. These risks can affect revenues and cash flows, and the Company's risk-management policies provide for the use of derivative instruments to manage these risks. The types of commodity derivative instruments used by the Company include futures, swaps, options, and fixed-price physical-delivery contracts. The volume of commodity derivatives entered into by the Company is governed by risk-management policies and may vary from year to year. Both exchange and over-the-counter traded derivative instruments may be subject to margin-deposit requirements, and the Company may be required from time to time to deposit cash or provide letters of credit with exchange brokers or counterparties to satisfy these margin requirements. For additional information relating to the Company's derivative and financial instruments, see *Note 9—Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

COMMODITY-PRICE RISK The Company's most significant market risk relates to prices for natural gas, oil, and NGLs. Management expects energy prices to remain unpredictable and potentially volatile. As energy prices decline or rise significantly, revenues and cash flows are likewise affected. In addition, a non-cash write-down of the Company's oil and gas properties or goodwill may be required if commodity prices experience a significant decline. Below is a sensitivity analysis for the Company's commodity-price-related derivative instruments.

Derivative Instruments Held for Non-Trading Purposes The Company had derivative instruments in place to reduce the price risk associated with future production of 30 MMBbls of oil, 14 Bcf of natural gas, and 1 MMBbls of NGLs at December 31, 2015, with a net derivative asset position of $273 million. Based on actual derivative contractual volumes, a 10% increase in underlying commodity prices would reduce the fair value of these derivatives by $58 million, while a 10% decrease in underlying commodity prices would increase the fair value of these derivatives by $44 million. However, any cash received or paid to settle these derivatives would be substantially offset by the sales value of production covered by the derivative instruments.

Derivative Instruments Held for Trading Purposes At December 31, 2015, the Company had a net derivative asset position of $17 million on outstanding derivative instruments entered into for trading purposes. Based on actual derivative contractual volumes, a 10% increase or decrease in underlying commodity prices would not materially impact the Company's gains or losses on these derivative instruments.

For additional information regarding the Company's marketing and trading portfolio, see *Marketing Activities* under Items 1 and 2 of this Form 10-K.

INTEREST-RATE RISK Borrowings under each of the 364-Day Facility, the Five-Year Facility, the commercial paper program, and WES's RCF are subject to variable interest rates. The balance of Anadarko's long-term debt on the Company's Consolidated Balance Sheets has fixed interest rates. The Company has $2.9 billion of obligations based on the London Interbank Offered Rate (LIBOR) that are presented on the Company's Consolidated Balance Sheets net of preferred investments in two non-controlled entities. These obligations give rise to minimal net interest-rate risk because coupons on the related preferred investments are also LIBOR-based. While a 10% change in LIBOR would not materially impact the Company's interest cost, it would affect the fair value of outstanding fixed-rate debt.

At December 31, 2015, the Company had a net derivative liability position of $1.5 billion related to interest-rate swaps. A 10% increase (decrease) in the three-month LIBOR interest-rate curve would increase (decrease) the aggregate fair value of outstanding interest-rate swap agreements by $103 million. However, any change in the interest-rate derivative gain or loss could be substantially offset by changes in actual borrowing costs associated with future debt issuances. For a summary of the Company's outstanding interest-rate derivative positions, see *Note 9—Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

FOREIGN-CURRENCY EXCHANGE-RATE RISK Anadarko's operating revenues are denominated in U.S. dollars, and the predominant portion of Anadarko's capital and operating expenditures are also U.S.-dollar-denominated. Exposure to foreign-currency risk generally arises in connection with project-specific contractual arrangements and other commitments. Near-term foreign-currency-denominated expenditures are primarily in Colombian pesos, Mozambican meticais, British pounds sterling, and Brazilian reais.

The Company also has risk related to exchange-rate changes applicable to cash held in escrow pending final determination of the Company's Brazilian tax liability for its 2008 divestiture of the Peregrino field offshore Brazil, which is currently under consideration by the Brazilian courts. See *Note 15—Contingencies—Other Litigation* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K. At December 31, 2015, cash of $86 million was held in escrow.

Management periodically engages in various risk-management activities to mitigate a portion of its exposure to foreign-currency exchange-rate risk. A 10% increase or decrease in the foreign-currency exchange rate would not materially impact the Company's gain or loss related to foreign currency.

Item 8. Financial Statements and Supplementary Data

ANADARKO PETROLEUM CORPORATION

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

ANADARKO PETROLEUM CORPORATION

REPORT OF MANAGEMENT

Management prepared, and is responsible for, the Consolidated Financial Statements and the other information appearing in this annual report. The Consolidated Financial Statements present fairly the Company's financial condition, results of operations and cash flows in conformity with accounting principles generally accepted in the United States. In preparing its Consolidated Financial Statements, the Company includes amounts that are based on estimates and judgments that Management believes are reasonable under the circumstances. The Company's financial statements have been audited by KPMG LLP, an independent registered public accounting firm appointed by the Audit Committee of the Board of Directors. Management has made available to KPMG LLP all of the Company's financial records and related data, as well as the minutes of the stockholders' and Directors' meetings.

MANAGEMENT'S ASSESSMENT OF INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining adequate internal control over financial reporting. Anadarko's internal control system was designed to provide reasonable assurance to the Company's Management and Directors regarding the preparation and fair presentation of published financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2015. This assessment was based on criteria established in the *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on our assessment, we believe that as of December 31, 2015, the Company's internal control over financial reporting was effective based on those criteria.

KPMG LLP has issued an attestation report on the Company's internal control over financial reporting as of December 31, 2015.

/s/ R. A. WALKER

R. A. Walker
Chairman, President and Chief Executive Officer

/s/ ROBERT G. GWIN

Robert G. Gwin
Executive Vice President, Finance and Chief Financial Officer

February 17, 2016

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Anadarko Petroleum Corporation:

We have audited Anadarko Petroleum Corporation's internal control over financial reporting as of December 31, 2015, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Anadarko Petroleum Corporation's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Assessment of Internal Control over Financial Reporting*. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Anadarko Petroleum Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Anadarko Petroleum Corporation and subsidiaries as of December 31, 2015 and 2014, and the related consolidated statements of income, comprehensive income, equity, and cash flows for each of the years in the three-year period ended December 31, 2015, and our report dated February 17, 2016 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Houston, Texas
February 17, 2016

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Anadarko Petroleum Corporation:

We have audited the accompanying consolidated balance sheets of Anadarko Petroleum Corporation and subsidiaries as of December 31, 2015 and 2014, and the related consolidated statements of income, comprehensive income, equity, and cash flows for each of the years in the three-year period ended December 31, 2015. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Anadarko Petroleum Corporation and subsidiaries as of December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the years in the three–year period ended December 31, 2015, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Anadarko Petroleum Corporation's internal control over financial reporting as of December 31, 2015, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 17, 2016 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP

Houston, Texas
February 17, 2016

ANADARKO PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF INCOME

	Years Ended December 31,		
millions except per-share amounts	**2015**	2014	2013
Revenues and Other			
Oil and condensate sales	**$ 5,420**	$ 9,748	$ 9,178
Natural-gas sales	**2,007**	3,849	3,388
Natural-gas liquids sales	**833**	1,572	1,262
Gathering, processing, and marketing sales	**1,226**	1,206	1,039
Gains (losses) on divestitures and other, net	**(788)**	2,095	(286)
Total	**8,698**	18,470	14,581
Costs and Expenses			
Oil and gas operating	**1,014**	1,171	1,092
Oil and gas transportation	**1,117**	1,116	981
Exploration	**2,644**	1,639	1,329
Gathering, processing, and marketing	**1,054**	1,030	869
General and administrative	**1,176**	1,316	1,090
Depreciation, depletion, and amortization	**4,603**	4,550	3,927
Other taxes	**553**	1,244	1,077
Impairments	**5,075**	836	794
Other operating expense	**271**	165	89
Total	**17,507**	13,067	11,248
Operating Income (Loss)	**(8,809)**	5,403	3,333
Other (Income) Expense			
Interest expense	**825**	772	686
(Gains) losses on derivatives, net	**(99)**	197	(398)
Other (income) expense, net	**149**	20	89
Tronox-related contingent loss	**5**	4,360	850
Total	**880**	5,349	1,227
Income (Loss) Before Income Taxes	**(9,689)**	54	2,106
Income tax expense (benefit)	**(2,877)**	1,617	1,165
Net Income (Loss)	**(6,812)**	(1,563)	941
Net income (loss) attributable to noncontrolling interests	**(120)**	187	140
Net Income (Loss) Attributable to Common Stockholders	**$ (6,692)**	$ (1,750)	$ 801
Per Common Share			
Net income (loss) attributable to common stockholders—basic	**$ (13.18)**	$ (3.47)	$ 1.58
Net income (loss) attributable to common stockholders—diluted	**$ (13.18)**	$ (3.47)	$ 1.58
Average Number of Common Shares Outstanding—Basic	**508**	506	502
Average Number of Common Shares Outstanding—Diluted	**508**	506	505
Dividends (per Common Share)	**$ 1.08**	$ 0.99	$ 0.54

See accompanying Notes to Consolidated Financial Statements.

ANADARKO PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Years Ended December 31,		
millions	**2015**	2014	2013
Net Income (Loss)	**$ (6,812)**	$ (1,563)	$ 941
Other Comprehensive Income (Loss)			
Adjustments for derivative instruments			
Reclassification of previously deferred derivative losses to (gains) losses on derivatives, net	**10**	9	11
Income taxes on reclassification of previously deferred derivative losses to (gains) losses on derivatives, net	**(4)**	(3)	(4)
Total adjustments for derivative instruments, net of taxes	**6**	6	7
Adjustments for pension and other postretirement plans			
Net gain (loss) incurred during period	**49**	(405)	416
Income taxes on net gain (loss) incurred during period	**(18)**	149	(152)
Prior service credit (cost) incurred during period	**89**	—	—
Income taxes on prior service credit (cost) incurred during period	**(33)**	—	—
Amortization of net actuarial (gain) loss to general and administrative expense	**63**	27	132
Income taxes on amortization of net actuarial (gain) loss to general and administrative expense	**(20)**	(9)	(49)
Amortization of net prior service (credit) cost to general and administrative expense	**(4)**	—	1
Income taxes on amortization of net prior service (credit) cost to general and administrative expense	**2**	—	—
Total adjustments for pension and other postretirement plans, net of taxes	**128**	(238)	348
Total	**134**	(232)	355
Comprehensive Income (Loss)	**(6,678)**	(1,795)	1,296
Comprehensive income (loss) attributable to noncontrolling interests	**(120)**	187	140
Comprehensive Income (Loss) Attributable to Common Stockholders	**$ (6,558)**	$ (1,982)	$ 1,156

See accompanying Notes to Consolidated Financial Statements.

ANADARKO PETROLEUM CORPORATION
CONSOLIDATED BALANCE SHEETS

millions	December 31, 2015	December 31, 2014
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 939**	$ 7,369
Accounts receivable (net of allowance of $11 million and $7 million)		
Customers	**652**	1,118
Others	**1,817**	1,409
Other current assets	**574**	603
Total	**3,982**	10,499
Properties and Equipment		
Cost	**70,683**	75,107
Less accumulated depreciation, depletion, and amortization	**36,932**	33,518
Net properties and equipment	**33,751**	41,589
Other Assets	**2,350**	2,310
Goodwill and Other Intangible Assets	**6,331**	6,569
Total Assets	**$ 46,414**	$ 60,967
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable	**$ 2,850**	$ 3,683
Current asset retirement obligations	**309**	257
Interest payable	**247**	247
Other taxes payable	**318**	332
Accrued expenses	**424**	505
Short-term debt	**33**	—
Tronox-related contingent liability	**—**	5,210
Total	**4,181**	10,234
Long-term Debt	**15,718**	15,092
Other Long-term Liabilities		
Deferred income taxes	**5,400**	8,527
Asset retirement obligations	**1,750**	1,796
Other	**3,908**	3,000
Total	**11,058**	13,323
Equity		
Stockholders' equity		
Common stock, par value $0.10 per share (1.0 billion shares authorized, 528.3 million and 525.9 million shares issued)	**52**	52
Paid-in capital	**9,265**	9,005
Retained earnings	**4,880**	12,125
Treasury stock (20.0 million and 19.3 million shares)	**(995)**	(940)
Accumulated other comprehensive income (loss)	**(383)**	(517)
Total Stockholders' Equity	**12,819**	19,725
Noncontrolling interests	**2,638**	2,593
Total Equity	**15,457**	22,318
Total Liabilities and Equity	**$ 46,414**	$ 60,967

See accompanying Notes to Consolidated Financial Statements.

ANADARKO PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF EQUITY

	Total Stockholders' Equity						
millions	Common Stock	Paid-in Capital	Retained Earnings	Treasury Stock	Accumulated Other Comprehensive Income (Loss)	Non-controlling Interests	Total Equity
Balance at December 31, 2012	$ 51	$ 8,230	$ 13,829	$ (841)	$ (640)	$ 1,253	$ 21,882
Net income (loss)	—	—	801	—	—	140	941
Common stock issued	1	292	—	—	—	—	293
Dividends—common stock	—	—	(274)	—	—	—	(274)
Repurchase of common stock	—	—	—	(54)	—	—	(54)
Subsidiary equity transactions	—	107	—	—	—	554	661
Distributions to noncontrolling interest owners	—	—	—	—	—	(156)	(156)
Contributions from noncontrolling interest owners	—	—	—	—	—	2	2
Reclassification of previously deferred derivative losses to (gains) losses on derivatives, net	—	—	—	—	7	—	7
Adjustments for pension and other postretirement plans	—	—	—	—	348	—	348
Balance at December 31, 2013	52	8,629	14,356	(895)	(285)	1,793	23,650
Net income (loss)	—	—	(1,750)	—	—	187	(1,563)
Common stock issued	—	286	—	—	—	—	286
Dividends—common stock	—	—	(505)	—	—	—	(505)
Repurchase of common stock	—	—	—	(45)	—	—	(45)
Subsidiary equity transactions	—	90	24	—	—	829	943
Distributions to noncontrolling interest owners	—	—	—	—	—	(216)	(216)
Reclassification of previously deferred derivative losses to (gains) losses on derivatives, net	—	—	—	—	6	—	6
Adjustments for pension and other postretirement plans	—	—	—	—	(238)	—	(238)
Balance at December 31, 2014	**52**	**9,005**	**12,125**	**(940)**	**(517)**	**2,593**	**22,318**
Net income (loss)	**—**	**—**	**(6,692)**	**—**	**—**	**(120)**	**(6,812)**
Common stock issued	**—**	**209**	**—**	**—**	**—**	**—**	**209**
Dividends—common stock	**—**	**—**	**(553)**	**—**	**—**	**—**	**(553)**
Repurchase of common stock	**—**	**—**	**—**	**(55)**	**—**	**—**	**(55)**
Subsidiary equity transactions	**—**	**51**	**—**	**—**	**—**	**99**	**150**
Issuance of tangible equity units	**—**	**—**	**—**	**—**	**—**	**348**	**348**
Distributions to noncontrolling interest owners	**—**	**—**	**—**	**—**	**—**	**(282)**	**(282)**
Reclassification of previously deferred derivative losses to (gains) losses on derivatives, net	**—**	**—**	**—**	**—**	**6**	**—**	**6**
Adjustments for pension and other postretirement plans	**—**	**—**	**—**	**—**	**128**	**—**	**128**
Balance at December 31, 2015	**$ 52**	**$ 9,265**	**$ 4,880**	**$ (995)**	**$ (383)**	**$ 2,638**	**$ 15,457**

See accompanying Notes to Consolidated Financial Statements.

ANADARKO PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

millions	Years Ended December 31, 2015	2014	2013
Cash Flows from Operating Activities			
Net income (loss)	**$ (6,812)**	$ (1,563)	$ 941
Adjustments to reconcile net income (loss) to net cash provided by operating activities			
Depreciation, depletion, and amortization	**4,603**	4,550	3,927
Deferred income taxes	**(3,152)**	(105)	90
Dry hole expense and impairments of unproved properties	**2,267**	1,245	864
Impairments	**5,075**	836	794
(Gains) losses on divestitures, net	**1,022**	(1,891)	470
Total (gains) losses on derivatives, net	**(100)**	207	(392)
Operating portion of net cash received (paid) in settlement of derivative instruments	**335**	371	85
Other	**320**	327	246
Changes in assets and liabilities			
Tronox-related contingent liability	**(5,210)**	4,360	850
(Increase) decrease in accounts receivable	**(2)**	103	719
Increase (decrease) in accounts payable and accrued expenses	**(995)**	97	148
Other items, net	**772**	(71)	146
Net cash provided by (used in) operating activities	**(1,877)**	8,466	8,888
Cash Flows from Investing Activities			
Additions to properties and equipment and dry hole costs	**(6,067)**	(9,508)	(7,721)
Acquisition of businesses	**(3)**	(1,527)	(473)
Divestitures of properties and equipment and other assets	**1,415**	4,968	567
Other, net	**(116)**	(405)	(589)
Net cash provided by (used in) investing activities	**(4,771)**	(6,472)	(8,216)
Cash Flows from Financing Activities			
Borrowings, net of issuance costs	**4,632**	2,879	958
Repayments of debt	**(4,033)**	(1,425)	(710)
Financing portion of net cash paid in settlement of derivative instruments	**(35)**	(222)	—
Increase (decrease) in outstanding checks	**(23)**	62	(13)
Dividends paid	**(553)**	(505)	(274)
Repurchase of common stock	**(55)**	(45)	(54)
Issuance of common stock, including tax benefit on share-based compensation awards	**34**	121	146
Sale of subsidiary units	**187**	1,026	724
Issuance of tangible equity units — equity component	**348**	—	—
Distributions to noncontrolling interest owners	**(282)**	(216)	(156)
Contributions from noncontrolling interest owners	**—**	—	2
Net cash provided by (used in) financing activities	**220**	1,675	623
Effect of Exchange Rate Changes on Cash	**(2)**	2	(68)
Net Increase (Decrease) in Cash and Cash Equivalents	**(6,430)**	3,671	1,227
Cash and Cash Equivalents at Beginning of Period	**7,369**	3,698	2,471
Cash and Cash Equivalents at End of Period	**$ 939**	$ 7,369	$ 3,698

See accompanying Notes to Consolidated Financial Statements.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2015, 2014, AND 2013

1. Summary of Significant Accounting Policies

General Anadarko Petroleum Corporation is engaged in the exploration, development, production, and marketing of oil, condensate, natural gas, and natural gas liquids (NGLs), and in the marketing of anticipated production of liquefied natural gas (LNG). In addition, the Company engages in the gathering, processing, treating, and transporting of oil, natural gas, and NGLs. The Company also participates in the hard-minerals business through royalty arrangements. Unless the context otherwise requires, the terms "Anadarko" and "Company" refer to Anadarko Petroleum Corporation and its consolidated subsidiaries.

Basis of Presentation The Consolidated Financial Statements have been prepared in conformity with generally accepted accounting principles in the United States (GAAP). The Consolidated Financial Statements include the accounts of Anadarko and entities in which it holds a controlling interest. All intercompany transactions have been eliminated. Undivided interests in oil and natural-gas exploration and production joint ventures are consolidated on a proportionate basis. Investments in non-controlled entities, over which Anadarko has the ability to exercise significant influence over operating and financial policies, are accounted for using the equity method. In applying the equity method of accounting, the investments are initially recognized at cost, and subsequently adjusted for the Company's proportionate share of earnings, losses, and distributions. Other investments are carried at original cost. Investments accounted for using the equity method and cost method are reported as a component of other assets. Certain prior-period amounts have been reclassified to conform to the current-year presentation.

Use of Estimates The preparation of financial statements in accordance with GAAP requires management to make informed judgments and estimates that affect the reported amounts of assets, liabilities, revenues, and expenses. Management evaluates its estimates and related assumptions regularly, including those related to proved reserves; the value of properties and equipment; goodwill; intangible assets; asset retirement obligations; litigation liabilities; environmental liabilities; pension assets, liabilities, and costs; income taxes; and fair values. Changes in facts and circumstances or additional information may result in revised estimates, and actual results may differ from these estimates.

Fair Value Fair value is defined as the price that would be received to sell an asset or the price paid to transfer a liability in an orderly transaction between market participants at the measurement date. Inputs used in determining fair value are characterized according to a hierarchy that prioritizes those inputs based on the degree to which they are observable. The three input levels of the fair-value hierarchy are as follows:

Level 1—Inputs represent unadjusted quoted prices in active markets for identical assets or liabilities (for example, exchange-traded futures contracts for which parties are willing to transact at the exchange-quoted price).

Level 2—Inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly (for example, quoted market prices for similar assets or liabilities in active markets or quoted market prices for identical assets or liabilities in markets not considered to be active, inputs other than quoted prices that are observable for the asset or liability, or market-corroborated inputs).

Level 3—Inputs that are not observable from objective sources such as the Company's internally developed assumptions used in pricing an asset or liability (for example, an estimate of future cash flows used in the Company's internally developed present value of future cash flows model that underlies the fair-value measurement).

In determining fair value, the Company uses observable market data when available, or models that incorporate observable market data. In addition to market information, the Company incorporates transaction-specific details that, in management's judgment, market participants would take into account in measuring fair value.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2015, 2014, AND 2013

1. Summary of Significant Accounting Policies (Continued)

In arriving at fair-value estimates, the Company uses relevant observable inputs available for the valuation technique employed. If a fair-value measurement reflects inputs at multiple levels within the hierarchy, the fair-value measurement is characterized based on the lowest level of input that is significant to the fair-value measurement. For Anadarko, recurring fair-value measurements are performed for interest-rate derivatives, commodity derivatives, and investments in trading securities.

The carrying amount of cash and cash equivalents, accounts receivable, and accounts payable reported on the Company's Consolidated Balance Sheets approximates fair value. The fair value of debt is the estimated amount the Company would have to pay to repurchase its debt, including any premium or discount attributable to the difference between the stated interest rate and market interest rate at each balance sheet date. Debt fair values, as disclosed in *Note 11—Debt and Interest Expense*, are based on quoted market prices for identical instruments, if available, or based on valuations of similar debt instruments.

Non-financial assets and liabilities initially measured at fair value include certain assets and liabilities acquired in a business combination or through a non-monetary exchange transaction, intangible assets, goodwill, asset retirement obligations, exit or disposal costs, and capital lease assets where the present value of lease payments is greater than the fair value of the leased asset.

Revenues The Company's oil and condensate are sold primarily to marketers, gatherers, and refiners. Natural gas is sold primarily to interstate and intrastate natural-gas pipelines, direct end-users, industrial users, local distribution companies, and natural-gas marketers. NGLs are sold primarily to direct end-users, refiners, and marketers.

The Company recognizes sales revenues for oil and condensate, natural gas, and NGLs based on the amount of each product sold to purchasers when delivery to the purchaser has occurred and title has transferred. This occurs when product has been delivered to a pipeline or when a tanker lifting has occurred. The Company follows the sales method of accounting for natural-gas production imbalances. If the Company's sales volumes for a well exceed the Company's proportionate share of production from the well, a liability is recognized to the extent that the Company's share of estimated remaining recoverable reserves from the well is insufficient to satisfy this imbalance. No receivables are recorded for those wells on which the Company has taken less than its proportionate share of production.

Anadarko provides gathering, processing, treating, and transporting services pursuant to a variety of contracts. Under these arrangements, the Company receives fees, or retains a percentage of products or a percentage of the proceeds from the sale of products and recognizes revenue at the time services are performed or product is sold. These revenues are included in gathering, processing, and marketing sales in the Company's Consolidated Statements of Income.

Marketing margins related to the Company's production are included in oil and condensate sales, natural-gas sales, and NGLs sales. Marketing margins related to sales of commodities purchased from third parties and gains and losses on derivatives related to such marketing activities are included in gathering, processing, and marketing sales in the Company's Consolidated Statements of Income.

The Company enters into buy/sell arrangements related to the transportation of a portion of its oil production. Under these arrangements, barrels are sold to a third party at a location-based contract price and subsequently repurchased by the Company at a downstream location. The difference in value between the sale and purchase price represents the transportation fee from the lease or certain gathering locations to more liquid markets. These arrangements are often required by private transporters. These transactions are reported on a net basis and included in oil and gas transportation in the Company's Consolidated Statements of Income.

Cash Equivalents The Company considers all highly liquid investments with a maturity of three months or less when purchased to be cash equivalents.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2015, 2014, AND 2013

1. Summary of Significant Accounting Policies (Continued)

Accounts Receivable and Allowance for Uncollectible Accounts The Company conducts credit analyses of customers prior to making any sales to new customers or increasing credit for existing customers. Based on these analyses, the Company may require a standby letter of credit or a financial guarantee. The Company charges uncollectible accounts receivable against the allowance for uncollectible accounts when it determines collection will no longer be pursued.

Inventories Commodity inventories are stated at the lower of average cost or market.

Properties and Equipment Properties and equipment are stated at cost less accumulated depreciation, depletion, and amortization (DD&A). Costs of improvements that appreciably improve the efficiency or productive capacity of existing properties or extend their lives are capitalized. Maintenance and repairs are expensed as incurred. Upon retirement or sale, the cost of properties and equipment, net of the related accumulated DD&A, is removed and, if appropriate, gain or loss is recognized in gains (losses) on divestitures and other, net in the Company's Consolidated Statements of Income.

Oil and Gas Properties The Company applies the successful efforts method of accounting for oil and gas properties. Exploration costs, such as exploratory geological and geophysical costs, delay rentals, and exploration overhead, are charged against earnings as incurred. If an exploratory well provides evidence to justify potential completion as a producing well, drilling costs associated with the well are initially capitalized, or suspended, pending a determination as to whether a commercially sufficient quantity of proved reserves can be attributed to the area as a result of drilling. This determination may take longer than one year in certain areas (generally in deepwater and international locations) depending on, among other things, the amount of hydrocarbons discovered, the outcome of planned geological and engineering studies, the need for additional appraisal drilling activities to determine whether the discovery is sufficient to support an economic development plan, and government sanctioning of development activities in certain international locations. At the end of each quarter, management reviews the status of all suspended exploratory drilling costs in light of ongoing exploration activities, in particular, whether the Company is making sufficient progress in its ongoing exploration and appraisal efforts or, in the case of discoveries requiring government sanctioning, analyzing whether development negotiations are underway and proceeding as planned. If management determines that future appraisal drilling or development activities are unlikely to occur, associated suspended exploratory well costs are expensed.

Acquisition costs of unproved properties are periodically assessed for impairment and are transferred to proved oil and gas properties to the extent the costs are associated with successful exploration activities. Significant undeveloped leases are assessed individually for impairment, based on the Company's current exploration plans, and a valuation allowance is provided if impairment is indicated. Unproved oil and gas properties with individually insignificant lease acquisition costs are amortized on a group basis (thereby establishing a valuation allowance) over the average lease terms at rates that provide for full amortization of unsuccessful leases upon lease expiration or abandonment. Costs of expired or abandoned leases are charged against the valuation allowance, while costs of productive leases are transferred to proved oil and gas properties. Costs of maintaining and retaining unproved properties, as well as amortization of individually insignificant leases and impairment of unsuccessful leases, are included in exploration expense in the Company's Consolidated Statements of Income.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2015, 2014, AND 2013

1. Summary of Significant Accounting Policies (Continued)

Capitalized Interest For significant projects, interest is capitalized as part of the historical cost of developing and constructing assets. Significant oil and gas investments in unproved properties, significant exploration and development projects that have not commenced production, significant midstream development activities that are in progress, and investments in equity-method affiliates that are undergoing the construction of assets that have not commenced principle operations qualify for interest capitalization. Interest is capitalized until the asset is ready for service. Capitalized interest is determined by multiplying the Company's weighted-average borrowing cost on debt by the average amount of qualifying costs incurred. Once an asset subject to interest capitalization is completed and placed in service, the associated capitalized interest is expensed through depreciation or impairment. See *Note 11—Debt and Interest Expense*.

Asset Retirement Obligations Asset retirement obligations (AROs) associated with the retirement of tangible long-lived assets are recognized as liabilities with an increase to the carrying amounts of the related long-lived assets in the period incurred. The cost of the tangible asset, including the asset retirement cost, is depreciated over the useful life of the asset. AROs are recorded at estimated fair value, measured by reference to the expected future cash outflows required to satisfy the retirement obligations discounted at the Company's credit-adjusted risk-free interest rate. Accretion expense is recognized over time as the discounted liabilities are accreted to their expected settlement value and is included in DD&A in the Company's Consolidated Statements of Income. If estimated future costs of AROs change, an adjustment is recorded to both the asset retirement obligation and the long-lived asset. Revisions to estimated AROs can result from changes in retirement cost estimates, revisions to estimated inflation rates, and changes in the estimated timing of abandonment. See *Note 13—Asset Retirement Obligations*.

Impairments Properties and equipment are reviewed for impairment when facts and circumstances indicate that net book values may not be recoverable. In performing this review, an undiscounted cash flow test is performed at the lowest level for which identifiable cash flows are independent of cash flows from other assets. If the sum of the undiscounted future net cash flows is less than the net book value of the property, an impairment loss is recognized for the excess, if any, of the property's net book value over its estimated fair value. See *Note 5—Impairments*.

Depreciation, Depletion, and Amortization Costs of drilling and equipping successful wells, costs to construct or acquire facilities other than offshore platforms, associated asset retirement costs, and capital lease assets used in oil and gas activities are depreciated using the unit-of-production (UOP) method based on total estimated proved developed oil and gas reserves. Costs of acquiring proved properties, including leasehold acquisition costs transferred from unproved properties and costs to construct or acquire offshore platforms and associated asset retirement costs, are depleted using the UOP method based on total estimated proved developed and undeveloped reserves. Mineral properties are also depleted using the UOP method. All other properties are stated at historical acquisition cost, net of impairments, and are depreciated using the straight-line method over the useful lives of the assets, which range from 3 to 15 years for furniture and equipment, up to 40 years for buildings, and up to 47 years for gathering facilities.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2015, 2014, AND 2013

1. Summary of Significant Accounting Policies (Continued)

Goodwill and Other Intangible Assets Anadarko has allocated goodwill to the following reporting units: oil and gas exploration and production; Western Gas Partners, LP (WES) gathering and processing; WES transportation; and other gathering and processing. Goodwill is subject to annual impairment testing in October (or more frequent testing as circumstances dictate). Anadarko's goodwill impairment test first assesses qualitative factors to determine whether goodwill is impaired. If the qualitative assessment indicates that it is more likely than not that the fair value of a reporting unit is less than its carrying amount, including goodwill, the Company will then perform a quantitative goodwill impairment test. Changes in goodwill may result from, among other things, impairments, acquisitions, or divestitures. See *Note 7—Goodwill and Other Intangible Assets*.

Other intangible assets represent contractual rights obtained in connection with business combinations that had favorable contractual terms relative to market at the acquisition date as well as customer-related intangible assets, including customer relationships established by acquired contracts. Other intangible assets are amortized over their estimated useful lives and are assessed for impairment whenever impairment indicators are present. See *Note 7—Goodwill and Other Intangible Assets*.

Derivative Instruments Anadarko uses derivative instruments to manage its exposure to cash-flow variability from commodity-price and interest-rate risks. Derivatives are carried on the balance sheet at fair value and are included in other current assets, other assets, accrued expenses, or other long-term liabilities, depending on the derivative position and the expected timing of settlement, unless they satisfy the normal purchases and sales exception criteria. Where the Company has the contractual right and intends to net settle, derivative assets and liabilities are reported on a net basis.

Gains and losses on derivative instruments are recognized currently in earnings. Net losses attributable to derivatives previously subject to hedge accounting reside in accumulated other comprehensive income (loss) and will be reclassified to earnings in future periods as the economic transactions to which the derivatives relate affect earnings. See *Note 9—Derivative Instruments*.

Accounts Payable Accounts payable included liabilities of $365 million at December 31, 2015, and $388 million at December 31, 2014, representing the amount by which checks issued, but not presented to the Company's banks for collection, exceeded balances in applicable bank accounts. Changes in these liabilities are reflected in cash flows from financing activities.

Legal Contingencies The Company is subject to legal proceedings, claims, and liabilities that arise in the ordinary course of business. Except for legal contingencies acquired in a business combination, which are recorded at fair value at the time of acquisition, the Company accrues losses associated with legal claims when such losses are probable and reasonably estimable. If the Company determines that a loss is probable and cannot estimate a specific amount for that loss, but can estimate a range of loss, the best estimate within the range is accrued. If no amount within the range is a better estimate than any other, the minimum amount of the range is accrued. Estimates are adjusted as additional information becomes available or circumstances change. Legal defense costs associated with loss contingencies are expensed in the period incurred. See *Note 15—Contingencies*.

**ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2015, 2014, AND 2013**

1. Summary of Significant Accounting Policies (Continued)

Environmental Contingencies The Company is subject to various environmental-remediation and reclamation obligations arising from federal, state, and local laws and regulations. Except for environmental contingencies acquired in a business combination, which are recorded at fair value at the time of acquisition, the Company accrues losses associated with environmental obligations when such losses are probable and reasonably estimable. Accruals for estimated environmental losses are recognized no later than at the time the remediation feasibility study, or the evaluation of response options, is complete. These accruals are adjusted as additional information becomes available or circumstances change. Future environmental expenditures are not discounted to their present value. Recoveries of environmental costs from other parties are recorded separately as assets at their undiscounted value when receipt of such recoveries is probable. See *Note 15—Contingencies*.

Noncontrolling Interests Noncontrolling interests represent third-party ownership in the net assets of the Company's consolidated subsidiaries and are presented as a component of equity. Changes in Anadarko's ownership interests in subsidiaries that do not result in deconsolidation are recognized in equity. See *Note 20—Noncontrolling Interests*.

Income Taxes The Company files various U.S. federal, state, and foreign income tax returns. Deferred federal, state, and foreign income taxes are provided on temporary differences between the financial statement carrying amounts of assets and liabilities and their respective tax basis. The Company routinely assesses the realizability of its deferred tax assets. If the Company concludes that it is more likely than not that some of the deferred tax assets will not be realized, the tax asset is reduced by a valuation allowance. The Company recognizes a tax benefit from an uncertain tax position when it is more likely than not that the position will be sustained upon examination, based on the technical merits of the position. The tax benefit recorded is equal to the largest amount that is greater than 50% likely to be realized through final settlement with a taxing authority. Interest and penalties related to unrecognized tax benefits are recognized in income tax expense (benefit). The Company uses the flow-through method to account for its investment tax credits. See *Note 12—Income Taxes*.

The Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2015-17, *Balance Sheet Classification of Deferred Taxes*. This ASU requires all deferred tax assets and liabilities, including any related valuation allowance, to be presented in the balance sheet as noncurrent. The Company has elected to adopt this ASU early using a retrospective approach. As a result of adoption, the Company reclassified $722 million from other current assets to deferred income taxes for the year ended December 31, 2014. See *Note 12—Income Taxes*.

Share-Based Compensation The Company accounts for share-based compensation at fair value. The Company grants equity-classified awards, including stock options and non-vested equity shares (restricted stock awards and units). The Company may also grant equity-classified and liability-classified awards based on a comparison of the Company's total shareholder return (TSR) to the TSR of a predetermined group of peer companies (performance units).

The fair value of stock option awards is determined using the Black-Scholes option-pricing model. Restricted stock awards and units are valued using the market price of Anadarko common stock. For other share-based compensation awards, fair value is determined using a Monte Carlo simulation.

The Company records compensation cost, net of estimated forfeitures, for share-based compensation awards over the requisite service period using the straight-line method. An adjustment is made to compensation cost for any difference between the estimated forfeitures and the actual forfeitures related to the awards. For equity-classified share-based compensation awards, expense is recognized based on the grant-date fair value. For liability-classified share-based compensation awards, expense is recognized for those awards expected to ultimately be paid. The amount of expense reported for liability-classified awards is adjusted for fair-value changes so that the expense recognized for each award is equivalent to the amount to be paid. See *Note 19—Share-Based Compensation*.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2015, 2014, AND 2013

1. Summary of Significant Accounting Policies (Continued)

Recently Issued Accounting Standards The FASB issued ASU 2016-01, *Financial Instruments—Overall: Recognition and Measurement of Financial Assets and Financial Liabilities (Subtopic 825-10).* This ASU amends existing requirements on the classification and measurement of financial instruments. Changes to the current requirements primarily affect the accounting for equity investments, financial liabilities under the fair value option, and the presentation and disclosure requirements for financial instruments. This ASU is effective for annual periods beginning in 2018 with early adoption of certain provisions permitted. The Company is evaluating the impact of the adoption of this ASU on its consolidated financial statements.

The FASB issued ASU 2015-03, *Interest—Imputation of Interest (Subtopic 835-30)—Simplifying the Presentation of Debt Issuance Costs* and ASU 2015-15, *Interest—Imputation of Interest (Subtopic 835-30)—Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements*. These ASUs require capitalized debt issuance costs, except for those related to revolving credit facilities, to be presented in the balance sheet as a direct deduction from the carrying amount of the related debt liability, rather than as an asset. The Company adopted these ASUs on January 1, 2016, using a retrospective approach. The adoption will result in a reclassification that will reduce other current assets and short-term debt by $1 million and reduce other assets and long-term debt by $82 million on the Company's Consolidated Balance Sheet at December 31, 2015, when included in future filings.

The FASB issued ASU 2015-02, *Consolidation—Amendments to the Consolidation Analysis*. This ASU amends existing requirements applicable to reporting entities that are required to evaluate consolidation of a legal entity under the variable interest entity (VIE) or voting interest entity models. The provisions will affect how limited partnerships and similar entities are assessed for consolidation, including an additional requirement that a limited partnership will be a VIE unless the limited partners have either substantive kick-out or participating rights over the general partner. This ASU is effective for annual and interim periods beginning in 2016 and is required to be adopted using a retrospective or modified retrospective approach, with early adoption permitted. The Company has evaluated the impact of the adoption of this ASU on its consolidated financial statements and determined that Western Gas Equity Partners, LP (WGP), and WES, publicly traded consolidated subsidiaries of the Company, meet the criteria for variable interest entities for which the Company is the primary beneficiary for accounting purposes. The adoption of this ASU will not have a material impact on the Company's consolidated financial statements; however, the VIE disclosure requirements will begin to apply in 2016 for the Company's interest in WGP and WES.

In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers*, which supersedes the revenue recognition requirements in Topic 605, *Revenue Recognition*, and industry-specific guidance in Subtopic 932-605, *Extractive Activities-Oil and Gas-Revenue Recognition* and requires an entity to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration the entity expects to be entitled to in exchange for those goods or services. The Company is required to adopt the new standard in the first quarter of 2018 using one of two retrospective application methods, with early adoption permitted in 2017. The Company is continuing to evaluate the provisions of this ASU, and has not determined the impact this standard may have on its consolidated financial statements and related disclosures or decided upon the method of adoption.

2. Inventories

The following summarizes the major classes of inventories included in other current assets at December 31:

millions	**2015**	2014
Oil	**$ 116**	$ 133
Natural gas	**36**	27
NGLs	**64**	83
Total inventories	**$ 216**	$ 243

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2015, 2014, AND 2013

3. Acquisitions, Divestitures, and Assets Held for Sale

Acquisitions In November 2014, WES acquired Nuevo Midstream, LLC (Nuevo), which owns and operates gathering and processing assets in the Delaware basin in West Texas, for $1.557 billion. Following the acquisition, WES changed the name of Nuevo to Delaware Basin Midstream, LLC (DBM). This acquisition constitutes a business combination and was accounted for using the acquisition method of accounting. This acquisition aligns the Company's gas gathering and processing capacity with future industry production growth plans in the Delaware basin. Preliminary fair-value measurements of assets acquired and liabilities assumed were finalized in the fourth quarter of 2015. There were no material changes to the fair value of assets acquired and liabilities assumed from the amounts included on the Company's Consolidated Balance Sheet at December 31, 2014. The following summarizes the fair value of assets acquired and liabilities assumed at the acquisition date:

millions		
Current assets	$	63
Properties and equipment		467
Other intangible assets		811
Accounts payable		(19)
Accrued expenses		(38)
Deferred income taxes		(1)
Asset retirement obligations		(9)
Goodwill		283
Total assets acquired and liabilities assumed	$	1,557

Fair-value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market and thus represent Level 3 inputs. The fair value of properties and equipment is based on market and cost approaches. Intangible assets consist of customer contracts, the fair value of which was determined using an income approach. Deferred tax assets (liabilities) represent the tax effects of differences in the tax basis and acquisition-date fair values of assets acquired and liabilities assumed. All of the goodwill related to this acquisition is amortizable for tax purposes. The assets acquired and liabilities assumed are included within the midstream reporting segment.

Results of operations attributable to this acquisition are included in the Company's Consolidated Statements of Income from the date acquired. The amounts of revenue and earnings included in the Company's Consolidated Statement of Income for the year ended December 31, 2014, and the amounts of revenue and earnings that would have been recognized had the acquisition occurred on January 1, 2014, are not material to the Company's Consolidated Statements of Income.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2015, 2014, AND 2013

3. Acquisitions, Divestitures, and Assets Held for Sale (Continued)

Divestitures and Assets Held for Sale The following summarizes the proceeds received and gains (losses) recognized on divestitures for the years ended December 31:

millions	**2015**	2014	2013
Proceeds received	$ **1,415**	$ 4,968	$ 567
Gains (losses) on divestitures, net	**(1,022)**	1,891	(470)

2015

- The Company sold certain coalbed methane properties and related midstream assets in the Rocky Mountains Region (Rockies) for net proceeds of $154 million, after closing adjustments, and recognized a loss of $538 million. These assets were included in the oil and gas exploration and production and midstream reporting segments.
- The Company sold certain U.S. onshore oil and gas properties and related midstream assets in East Texas, with a sales price of $440 million, for net proceeds of $425 million after closing adjustments, and recognized a loss of $110 million. These assets were included in the oil and gas exploration and production and midstream reporting segments.
- The Company sold certain enhanced oil recovery (EOR) assets in the Rockies, with a sales price of $703 million, for net proceeds of $675 million after closing adjustments, and recognized a loss of $350 million. These assets were included in the oil and gas exploration and production reporting segment.

2014 Total proceeds and net gains on divestitures during 2014 primarily related to assets included in the oil and gas exploration and production reporting segment as follows:

- The Company sold a 10% working interest in Offshore Area 1 in Mozambique for $2.64 billion and recognized a gain of $1.5 billion.
- The Company sold its Chinese subsidiary for $1.075 billion and recognized a gain of $510 million.
- The Company sold its interest in the nonoperated Vito deepwater development, along with several surrounding exploration blocks in the Gulf of Mexico for $500 million, and recognized a gain of $237 million.
- The Company sold its interest in the Pinedale/Jonah assets in Wyoming for $581 million.
- During the fourth quarter of 2014, Anadarko considered certain EOR assets in the Rockies to be held for sale and recognized losses of $456 million. These assets were remeasured to their fair value using a market approach and Level 2 fair-value measurement. Volatility in the then-current commodity-price environment had reduced the probability that the assets would be sold within one year and the assets were therefore no longer considered held for sale at December 31, 2014.

2013

- The Company sold its interests in a soda ash joint venture and certain U.S. onshore and Indonesian oil and gas properties and recognized net gains of $234 million, primarily related to the Company's divestiture of its interests in the soda ash joint venture and certain U.S. oil and gas properties included in the oil and gas exploration and production reporting segment.
- The Company recognized losses of $704 million primarily related to its Pinedale/Jonah assets included in the oil and gas exploration and production reporting segment considered to be held for sale at December 31, 2013. The sale of these assets closed in 2014 as discussed above.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2015, 2014, AND 2013

3. Acquisitions, Divestitures, and Assets Held for Sale (Continued)

Property Exchange In 2013, the Company exchanged certain oil and gas properties in the Wattenberg field with a third party. The properties exchanged were measured at the Company's historical net cost with no gain or loss recognized. Anadarko paid $106 million in cash as part of the exchange, which is included as an addition to properties and equipment on the Company's Consolidated Statement of Cash Flows for the year ended December 31, 2013.

4. Properties and Equipment

The following summarizes properties and equipment by segment at December 31:

millions	**2015**	2014
Oil and gas exploration and production [(1)]	**$ 59,389**	$ 63,674
Midstream	**8,458**	8,647
Other	**2,836**	2,786
Gross properties and equipment	**$ 70,683**	$ 75,107
Less accumulated depreciation, depletion, and amortization	**36,932**	33,518
Net properties and equipment	**$ 33,751**	$ 41,589

(1) Includes costs associated with unproved properties of $3.5 billion at December 31, 2015, and $5.1 billion at December 31, 2014.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2015, 2014, AND 2013

5. Impairments

Impairments of proved properties are included in impairment expense in the Company's Consolidated Statements of Income. The following summarizes impairments of proved properties and the related post-impairment fair values by segment at December 31:

	2015		2014		2013	
millions	**Impairment**	**Fair Value(1)**	Impairment	Fair Value(1)	Impairment	Fair Value(1)
Oil and gas exploration and production						
Long-lived assets held for use						
U.S. onshore properties	**$ 3,684**	**$ 1,253**	$ 545	$ 552	$ 142	$ 271
Gulf of Mexico properties	**349**	**65**	276	223	562	242
Cost-method investment (2)	**3**	**32**	3	32	11	32
Midstream						
Long-lived assets held for use	**1,039**	**212**	12	—	79	36
Total impairments	**$ 5,075**	**$ 1,562**	$ 836	$ 807	$ 794	$ 581

(1) Measured as of the impairment date using the income approach and Level 3 inputs.
(2) Represents the after-tax net investment.

2015 Impairments In 2015, impairments were primarily related to the Company's Greater Natural Buttes oil and gas and midstream properties in the Rockies, other U.S. onshore oil and gas properties primarily in the Southern and Appalachia Region, other midstream properties primarily in the Rockies, and oil and gas properties in the Gulf of Mexico, all of which were impaired due to lower forecasted commodity prices.

2014 Impairments In 2014, certain U.S. onshore and Gulf of Mexico oil and gas properties were impaired primarily due to lower forecasted commodity prices.

2013 Impairments In 2013, certain Gulf of Mexico properties were impaired due to a reduction in estimated future net cash flows and downward revisions of reserves resulting from changes to the Company's development plans. Also in 2013, certain U.S. onshore properties and related midstream assets were impaired due to downward revisions of reserves resulting from changes to the Company's development plans. In addition, a midstream property was impaired during 2013 due to a reduction in estimated future cash flows.

Impairments of Unproved Properties Impairments of unproved properties are included in exploration expense in the Company's Consolidated Statements of Income. In 2015, the Company recognized a $935 million impairment of unproved Greater Natural Buttes properties and a $66 million impairment of an unproved Gulf of Mexico property as a result of lower commodity prices. Also in 2015, the Company recognized a $109 million impairment of unproved Utica properties resulting from an assignment of mineral interests in settlement of a legal matter.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2015, 2014, AND 2013

5. Impairments (Continued)

Potential for Future Impairments During 2015, the Company recognized significant impairments of proved oil and gas and midstream properties and impairments of unproved oil and gas properties, primarily as a result of lower forecasted commodity prices and changes to the Company's drilling plans. At December 31, 2015, the Company's estimate of undiscounted future cash flows attributable to a certain depletion group with a net book value of approximately $2.2 billion indicated that the carrying amount was expected to be recovered; however, this depletion group may be at risk for impairment if the estimates of future cash flows decline. The Company estimates that, if this depletion group becomes impaired in a future period, the Company could recognize non-cash impairments in that period in excess of $800 million. It is also reasonably possible that prolonged low or further declines in commodity prices, further changes to the Company's drilling plans in response to lower prices, or increases in drilling or operating costs could result in other additional impairments.

6. Suspended Exploratory Well Costs

The following summarizes the changes in suspended exploratory well costs at December 31 for each of the last three years. Additions pending the determination of proved reserves excludes amounts capitalized and subsequently charged to expense within the same year.

millions	**2015**	2014	2013
Balance at January 1	**$ 1,522**	$ 2,232	$ 2,062
Additions pending the determination of proved reserves	**461**	421	848
Divestitures and other [(1)]	**(33)**	(913)	(48)
Reclassifications to proved properties	**(104)**	(100)	(507)
Charges to exploration expense [(2)]	**(722)**	(118)	(123)
Balance at December 31	**$ 1,124**	$ 1,522	$ 2,232

(1) Includes $(744) million during 2014 related to the Company's sale of a 10% working interest in Offshore Area 1 in Mozambique.

(2) Includes $(565) million during 2015 related to Brazil. Given the current oil-price environment and other considerations, the Company does not expect to have substantive exploration and development activities in Brazil in the foreseeable future.

The following provides an aging of suspended well balances at December 31:

millions	**2015**	2014	2013
Exploratory well costs capitalized for a period of one year or less	**$ 452**	$ 393	$ 836
Exploratory well costs capitalized for a period greater than one year	**672**	1,129	1,396
Balance at December 31	**$ 1,124**	$ 1,522	$ 2,232

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2015, 2014, AND 2013

6. Suspended Exploratory Well Costs (Continued)

The following summarizes a further aging by geographic area of those exploratory well costs that have been capitalized for a period greater than one year since the completion of drilling at December 31, 2015:

millions except projects	Number of Projects	Total	2014	2013	2012 and prior
United States—Onshore	18	$ 55	$ 34	$ 11	$ 10
United States—Offshore	4	314	77	80	157
International	7	303	119	3	181
	29	$ 672	$ 230	$ 94	$ 348

Projects with suspended exploratory well costs are those identified by management as exhibiting sufficient quantities of hydrocarbons to justify potential development and where management is actively pursuing efforts to assess whether reserves can be attributed to these projects. Suspended exploratory well costs capitalized for a period greater than one year after completion of drilling at December 31, 2015, primarily related to the Gulf of Mexico, Ghana, and Mozambique.

For projects located in the Gulf of Mexico, the majority of exploratory well costs capitalized greater than one year are related to the Shenandoah discovery. Well costs have been suspended pending further appraisal activities, including drilling and analysis of well results. Appraisal activities undertaken at the Shenandoah discovery include the acquisition of whole-core across the primary reservoir interval, the processing and analysis of seismic data, reservoir simulation modeling, and analysis of well results. Remaining activities required to classify the associated reserves as proved for the Shenandoah discovery include completion of geologic, reservoir, and economic modeling; product development testing; and pre-front-end engineering and design (FEED) and FEED engineering studies.

For projects located in Ghana, exploratory well costs that have been capitalized greater than one year are pending development plan approval. During the fourth quarter of 2015, the Company and its partners submitted the Jubilee full field development plan for the Mahogany East and Teak areas. Remaining activities required to classify the associated reserves as proved include approval of development plans and project sanctioning.

For projects located in Mozambique, the majority of exploratory well costs capitalized greater than one year are related to the Orca, Tubarão, and Tubarão Tigre discoveries. Well costs have been suspended pending further appraisal activities, including analysis of well results and seismic reprocessing. During 2015, drilling and evaluation operations at the Tubarão Tigre-2 appraisal well were completed. Anadarko is continuing to appraise the Orca, Tubarão, and Tubarão Tigre discoveries in accordance with the appraisal programs provided to the government of Mozambique in the first quarter of 2015.

If additional information becomes available that raises substantial doubt as to the economic or operational viability of any of these projects, the associated costs will be expensed at that time.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2015, 2014, AND 2013

7. Goodwill and Other Intangible Assets

Goodwill At December 31, 2015, the Company had $5.4 billion of goodwill allocated to the following reporting units: $4.9 billion to oil and gas exploration and production, $383 million to WES gathering and processing, $5 million to WES transportation, and $62 million to other gathering and processing. The Company's 2015 annual impairment assessment of goodwill indicated no impairment. An additional assessment was also performed in December 2015 to consider the impact of commodity-price changes since the annual test. This assessment also indicated no impairment.

Although commodity prices declined during the year, as of December 31, 2015, the estimated fair value of the oil and gas reporting unit exceeded the carrying value by more than 15%, without consideration for any control premium, and the other reporting units were not at risk of impairment. However, prolonged low or further declines in commodity prices, decreases in proved reserves, changes in exploration or development plans, significant property impairments, increases in operating or drilling costs, significant changes in regulations, or other negative changes to the economic environment in which Anadarko operates, could result in further goodwill impairment tests in the near term, the results of which may have a material adverse impact on the Company's results of operations.

Other Intangible Assets Intangible assets and associated amortization expense were as follows:

millions	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Amortization Expense
December 31, 2015				
Offshore platform leases	**$ 33**	**$ (31)**	**$ 2**	**$ 2**
Customer contracts	**980**	**(46)**	**934**	**31**
	$ 1,013	**$ (77)**	**$ 936**	**$ 33**
December 31, 2014				
Offshore platform leases	$ 33	$ (29)	$ 4	$ —
Customer contracts	1,004	(15)	989	6
	$ 1,037	$ (44)	$ 993	$ 6

Customer contract intangible assets are primarily related to WES's DBM acquisition in 2014. These contracts are being amortized over 30 years. See *Note 3—Acquisitions, Divestitures, and Assets Held for Sale*. The annual aggregate amortization expense for intangible assets is expected to be $31 million each of the next five years.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2015, 2014, AND 2013

8. Equity-Method Investments

In 2007, Anadarko contributed certain of its oil and gas properties and gathering and processing assets, with an aggregate fair value of $2.9 billion at the time of the contribution, to newly formed unconsolidated entities in exchange for noncontrolling mandatorily redeemable London Interbank Offered Rate (LIBOR) based preferred interests in those entities. The common equity of the investee entities is 95% owned by third parties that also maintain control over the assets. Subsequent to their formation, the investee entities loaned Anadarko an aggregate of $2.9 billion. The Company accounts for its investment in these entities using the equity method of accounting. The carrying amount of these investments was $2.8 billion and the carrying amount of notes payable to affiliates was $2.9 billion at December 31, 2015. Anadarko has legal right of setoff and intends to net settle its obligations under each of the notes payable to the investees with the distributable value of its interest in the corresponding investee. Accordingly, the investments and the obligations are presented net on the Company's Consolidated Balance Sheets in other long-term liabilities—other for all periods presented.

Interest on the notes issued by Anadarko is variable, and is equivalent to LIBOR plus a spread that fluctuates with Anadarko's credit rating. The applicable interest rate was 1.51% at December 31, 2015, and 1.24% at December 31, 2014. The note payable agreement contains a covenant that provides for a maximum Anadarko debt-to-capital ratio of 67% (excluding the effect of non-cash write-downs). Anadarko was in compliance with this covenant at December 31, 2015. Other (income) expense, net includes interest expense on the notes payable of $37 million in 2015, $36 million in 2014, and $37 million in 2013, and equity (earnings) losses from Anadarko's investments in the investee entities of $15 million in 2015, $(45) million in 2014, and $(42) million in 2013.

9. Derivative Instruments

Objective and Strategy The Company uses derivative instruments to manage its exposure to cash-flow variability from commodity-price and interest-rate risks. Futures, swaps, and options are used to manage exposure to commodity-price risk inherent in the Company's oil and natural-gas production and natural-gas processing operations (Oil and Natural-Gas Production/Processing Derivative Activities). Futures contracts and commodity-price swap agreements are used to fix the price of expected future oil and natural-gas sales at major industry trading locations such as Henry Hub, Louisiana for natural gas and Cushing, Oklahoma or Sullom Voe, Scotland for oil. Basis swaps are periodically used to fix or float the price differential between product prices at one market location versus another. Options are used to establish a floor price, a ceiling price, or a floor and a ceiling price (collar) for expected future oil and natural-gas sales. Derivative instruments are also used to manage commodity-price risk inherent in customer price requirements and to fix margins on the future sale of natural gas and NGLs from the Company's leased storage facilities (Marketing and Trading Derivative Activities).

Interest-rate swaps are used to fix or float interest rates on existing or anticipated indebtedness. The purpose of these instruments is to manage the Company's existing or anticipated exposure to interest-rate changes. The fair value of the Company's current interest-rate swap portfolio increases (decreases) when interest rates increase (decrease).

The Company does not apply hedge accounting to any of its derivative instruments. As a result, gains and losses associated with derivative instruments are recognized currently in earnings. Net derivative losses attributable to derivatives previously subject to hedge accounting reside in accumulated other comprehensive income (loss) and are reclassified to earnings as the transactions to which the derivatives relate are recognized in earnings. See *Note 18—Accumulated Other Comprehensive Income (Loss)*.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2015, 2014, AND 2013

9. Derivative Instruments (Continued)

Oil and Natural-Gas Production/Processing Derivative Activities The oil prices listed below are a combination of New York Mercantile Exchange (NYMEX) West Texas Intermediate and Intercontinental Exchange, Inc. (ICE) Brent Blend prices. The natural-gas prices listed below are NYMEX Henry Hub prices. The NGLs prices listed below are Oil Price Information Services prices (OPIS). The following is a summary of the Company's derivative instruments related to oil and natural-gas production/processing derivative activities at December 31, 2015:

	2016 Settlement
Oil	
Three-Way Collars (MBbls/d)	83
Average price per barrel	
Ceiling sold price (call)	$ 63.82
Floor purchased price (put)	$ 54.46
Floor sold price (put)	$ 42.77
Natural Gas	
Fixed-Price Contracts (thousand MMBtu/d)	38
Average price per MMBtu	$ 2.53
NGLs	
Fixed-Price Contracts (MBbls/d)	4
Average price per barrel	$ 13.07

MMBtu—million British thermal units
MMBtu/d—million British thermal units per day

A three-way collar is a combination of three options: a sold call, a purchased put, and a sold put. The sold call establishes the maximum price that the Company will receive for the contracted commodity volumes. The purchased put establishes the minimum price that the Company will receive for the contracted volumes unless the market price for the commodity falls below the sold put strike price, at which point the minimum price equals the reference price (e.g., NYMEX) plus the excess of the purchased put strike price over the sold put strike price.

In 2014, the Company terminated or offset then-existing 2015 oil three-way collars with a notional volume of 25 thousand barrels per day due to lower oil prices, resulting in a cash receipt of $126 million.

Marketing and Trading Derivative Activities The Company had financial derivative transactions with notional volumes of natural gas totaling 8 billion cubic feet (Bcf) at December 31, 2015, and 6 Bcf at December 31, 2014, that were entered into to mitigate commodity-price risk related to fixed-price purchase and sales contracts and storage activity.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2015, 2014, AND 2013

9. Derivative Instruments (Continued)

Interest-Rate Derivatives Anadarko has outstanding interest-rate swap contracts to manage interest-rate risk associated with anticipated debt issuances. The Company has locked in a fixed interest rate in exchange for a floating interest rate indexed to the three-month LIBOR.

In 2015, the Company extended the reference-period start dates on interest-rate swaps with an aggregate notional principal amount of $1.0 billion to align the portfolio with anticipated debt refinancing. The Company also amended the mandatory termination dates on interest-rate swaps with an aggregate notional principal amount of $1.8 billion so that, at the start of the reference period, Anadarko will receive quarterly payments based on the floating rate and make semi-annual payments based on the fixed interest rate. The interest-rate swaps are required to be settled in full at the mandatory termination date. As part of these interest-rate swap modifications, the fixed interest rates on the swaps were also adjusted, and the Company recognized a loss of $137 million, which is included in gains (losses) on derivatives, net in the Company's Consolidated Statement of Income, and increased the related derivative liability. In 2014, in anticipation of the July 2014 issuance of an aggregate $1.25 billion of Senior Notes, interest-rate swap agreements with an aggregate notional principal amount of $750 million were settled in 2014, resulting in a cash payment of $222 million.

Derivative settlements and collateralization are classified as cash flows from operating activities unless the derivatives contain an other-than-insignificant financing element, in which case the settlements and collateralization are classified as cash flows from financing activities. As a result of prior extensions of reference-period start dates without settlement of the related interest-rate derivative obligations, the interest-rate derivatives in the Company's portfolio contain an other-than-insignificant financing element, and therefore, any settlements or collateralization related to these extended interest-rate derivatives are classified as cash flows from financing activities.

The Company had the following outstanding interest-rate swaps at December 31, 2015:

millions except percentages Notional Principal Amount		Reference Period	Mandatory Termination Date	Weighted-Average Interest Rate
$	50	September 2016 – 2026	September 2016	5.910%
$	50	September 2016 – 2046	September 2016	6.290%
$	250	September 2016 – 2046	September 2018	6.310%
$	300	September 2016 – 2046	September 2020	6.509%
$	250	September 2016 – 2046	September 2021	6.724%
$	200	September 2017 – 2047	September 2018	6.049%
$	300	September 2017 – 2047	September 2020	6.569%
$	500	September 2017 – 2047	September 2021	6.654%

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2015, 2014, AND 2013

9. Derivative Instruments (Continued)

Effect of Derivative Instruments—Balance Sheet The following summarizes the fair value of the Company's derivative instruments at December 31:

millions	Gross Derivative Assets		Gross Derivative Liabilities	
Balance Sheet Classification	**2015**	2014	**2015**	2014
Commodity derivatives				
Other current assets	**$ 462**	$ 421	**$ (177)**	$ (118)
Other assets	**8**	1	**—**	—
Accrued expenses	**—**	71	**(3)**	(114)
Other liabilities	**—**	—	**—**	(6)
	470	493	**(180)**	(238)
Interest-rate derivatives				
Other current assets	**2**	—	**—**	—
Other assets	**54**	—	**—**	—
Accrued expenses	**—**	—	**(54)**	—
Other liabilities	**—**	—	**(1,488)**	(1,217)
	56	—	**(1,542)**	(1,217)
Total derivatives	**$ 526**	$ 493	**$ (1,722)**	$ (1,455)

Effect of Derivative Instruments—Statement of Income The following summarizes gains and losses related to derivative instruments:

millions			
Classification of (Gain) Loss Recognized	**2015**	2014	2013
Commodity derivatives			
Gathering, processing, and marketing sales [(1)]	**$ (1)**	$ 10	$ 6
(Gains) losses on derivatives, net	**(367)**	(589)	141
Interest-rate derivatives			
(Gains) losses on derivatives, net	**268**	786	(539)
Total (gains) losses on derivatives, net	**$ (100)**	$ 207	$ (392)

(1) Represents the effect of Marketing and Trading Derivative Activities.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2015, 2014, AND 2013

9. Derivative Instruments (Continued)

Credit-Risk Considerations The financial integrity of exchange-traded contracts, which are subject to nominal credit risk, is assured by NYMEX or ICE through systems of financial safeguards and transaction guarantees. Over-the-counter traded swaps, options, and futures contracts expose the Company to counterparty credit risk. The Company monitors the creditworthiness of its counterparties, establishes credit limits according to the Company's credit policies and guidelines, and assesses the impact on the fair value of its counterparties' creditworthiness. The Company has the ability to require cash collateral or letters of credit to mitigate its credit-risk exposure.

The Company has netting agreements with financial institutions that permit net settlement of gross commodity derivative assets against gross commodity derivative liabilities, and routinely exercises its contractual right to offset gains and losses when settling with derivative counterparties. In addition, the Company has setoff agreements with certain financial institutions that may be exercised in the event of default and provide for contract termination and net settlement across derivative types. At December 31, 2015, $347 million of the Company's $1.722 billion gross derivative liability balance, and at December 31, 2014, $289 million of the Company's $1.455 billion gross derivative liability balance would have been eligible for setoff against the Company's gross derivative asset balance in the event of default. Other than in the event of default, the Company does not net settle across derivative types.

The Company's derivative instruments are subject to individually negotiated credit provisions that may require collateral of cash or letters of credit depending on the derivative's valuation versus negotiated credit thresholds. These credit thresholds may also require full or partial collateralization or immediate settlement of the Company's obligations if certain credit-risk-related provisions are triggered such as if the Company's credit rating from major credit rating agencies declines to a level that is below investment grade. Previously, most of the Company's derivative counterparties maintained secured positions with respect to the Company's derivative liabilities under the Company's $5.0 billion senior secured revolving credit facility ($5.0 billion Facility). In January 2015, the Company's $5.0 billion Facility was replaced by new unsecured facilities under which the Company's derivative counterparties no longer maintain security interests in any of the Company's assets. As a result, the Company may be required from time to time to post collateral of cash or letters of credit based on the negotiated terms of the individual derivative agreements. The aggregate fair value of derivative instruments with credit-risk-related contingent features for which a net liability position existed was $1.3 billion (net of collateral) at December 31, 2015, and $97 million (net of collateral) at December 31, 2014. For information on the Company's revolving credit facilities, see *Note 11—Debt and Interest Expense—Anadarko Revolving Credit Facilities and Commercial Paper Program*.

**ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2015, 2014, AND 2013**

9. Derivative Instruments (Continued)

Fair Value Fair value of futures contracts is based on unadjusted quoted prices in active markets for identical assets or liabilities, which represent Level 1 inputs. Valuations of physical-delivery purchase and sale agreements, over-the-counter financial swaps, and commodity option collars are based on similar transactions observable in active markets and industry-standard models that primarily rely on market-observable inputs. Inputs used to estimate fair value in industry-standard models are categorized as Level 2 inputs because substantially all assumptions and inputs are observable in active markets throughout the full term of the instruments. Inputs used to estimate the fair value of swaps and options include market-price curves; contract terms and prices; credit-risk adjustments; and, for Black-Scholes option valuations, discount factors and implied market volatility.

The following summarizes the fair value of the Company's derivative assets and liabilities, by input level within the fair-value hierarchy:

millions	Level 1	Level 2	Level 3	Netting [1]	Collateral	Total
December 31, 2015						
Assets						
Commodity derivatives	**$ 10**	**$ 460**	**$ —**	**$ (178)**	**$ (8)**	**$ 284**
Interest-rate derivatives	**—**	**56**	**—**	**—**	**—**	**56**
Total derivative assets	**$ 10**	**$ 516**	**$ —**	**$ (178)**	**$ (8)**	**$ 340**
Liabilities						
Commodity derivatives	**$ (1)**	**$ (179)**	**$ —**	**$ 178**	**$ —**	**$ (2)**
Interest-rate derivatives	**—**	**(1,542)**	**—**	**—**	**58**	**(1,484)**
Total derivative liabilities	**$ (1)**	**$ (1,721)**	**$ —**	**$ 178**	**$ 58**	**$ (1,486)**
December 31, 2014						
Assets						
Commodity derivatives	$ —	$ 493	$ —	$ (189)	$ (13)	$ 291
Total derivative assets	$ —	$ 493	$ —	$ (189)	$ (13)	$ 291
Liabilities						
Commodity derivatives	$ —	$ (238)	$ —	$ 189	$ —	$ (49)
Interest-rate derivatives	—	(1,217)	—	—	23	(1,194)
Total derivative liabilities	$ —	$ (1,455)	$ —	$ 189	$ 23	$ (1,243)

(1) Represents the impact of netting commodity derivative assets and liabilities with counterparties where the Company has the contractual right and intends to net settle.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2015, 2014, AND 2013

10. Tangible Equity Units

In June 2015, the Company issued 9.2 million 7.50% tangible equity units (TEUs) at a stated amount of $50.00 per TEU and raised net proceeds of $445 million. Each TEU is comprised of a prepaid equity purchase contract for common units of WGP and a senior amortizing note. Subsequent to issuance, each TEU may be legally separated into the two components. The prepaid equity purchase contract is considered a freestanding financial instrument, indexed to WGP common units, and meets the conditions for equity classification.

Anadarko allocated the proceeds from the issuance of the TEUs to equity and debt based on the relative fair values of their respective components as follows:

millions, except price per TEU	Equity Component	Debt Component	Total
Price per TEU	$ 39.05	$ 10.95	$ 50.00
Gross proceeds	359	101	460
Less issuance costs	11	4	15
Net proceeds	$ 348	$ 97	$ 445

The prepaid equity purchase contracts were recorded in noncontrolling interests, net of issuance costs, and the senior amortizing notes were recorded in short-term debt and long-term debt on the Company's Consolidated Balance Sheet.

Equity Component Unless settled earlier at the holder's option, each purchase contract has a mandatory settlement date of June 7, 2018. Anadarko has a right to elect to issue and deliver shares of Anadarko Petroleum Corporation common stock (APC shares) in lieu of delivering WGP common units at settlement. The Company will deliver WGP common units (or APC shares) on the settlement date at the settlement rate based upon the applicable market value of WGP common units (or APC shares) as follows:

	Settlement Rate per Purchase Contract	
Applicable Market Value of WGP Common Units [(1)]	**WGP Common Units**	**APC Shares (if elected)** [(1)]
Exceeds $69.8422 (Threshold Appreciation Price)	0.7159 units (Minimum Settlement Rate)	a number of shares equal to (a) the Minimum Settlement Rate, multiplied by the applicable market value of WGP common units, divided by (b) 98% of the applicable market value of APC shares
Less than or equal to the Threshold Appreciation Price, but greater than or equal to $58.20 (Reference Price)	a number of units equal to $50.00, divided by the applicable market value of WGP common units	a number of shares equal to $50.00, divided by 98% of the applicable market value of APC shares
Less than the Reference Price	0.8591 units (Maximum Settlement Rate)	a number of shares equal to (a) the Maximum Settlement Rate, multiplied by the applicable market value of WGP common units, divided by (b) 98% of the applicable market value of APC shares

(1) The applicable market value is the average of the daily volume-weighted average prices of WGP common units (or APC shares) for the 20 consecutive trading days beginning on, and including, the 23rd scheduled trading day immediately preceding June 7, 2018.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2015, 2014, AND 2013

10. Tangible Equity Units (Continued)

The WGP common units underlying the purchase contract are currently issued and outstanding, and are owned by a wholly owned subsidiary of Anadarko. In the event Anadarko elects to settle in APC shares, the number of such shares issued and delivered upon settlement of each purchase contract is subject to adjustment and cannot exceed four shares under any circumstance (APC share cap). The above fixed settlement rates for WGP common units and the APC share cap are subject to adjustment upon the occurrence of certain specified dilutive events such as certain increases in the WGP distribution rate.

Debt Component Each senior amortizing note has an initial principal amount of $10.95 and bears interest at 1.50% per year. Beginning September 7, 2015, Anadarko will pay equal quarterly cash installments of $0.9375 per amortizing note (except for the September 7, 2015 installment payment, which was $0.9063 per amortizing note). The payments constitute a payment of interest and partial repayment of principal, with the aggregate per-year payments of principal and interest equating to a 7.50% cash payment with respect to each TEU. The senior amortizing notes have a final installment payment date of June 7, 2018, and are senior unsecured obligations of the Company.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2015, 2014, AND 2013

11. Debt and Interest Expense

Debt The Company's outstanding debt, excluding the capital lease obligation, is senior unsecured. See *Note 8—Equity-Method Investments* for disclosure regarding Anadarko's notes payable related to its ownership of certain noncontrolling mandatorily redeemable interests that are not included in the Company's reported debt balance and do not affect consolidated interest expense. The following summarizes the Company's outstanding debt:

	December 31,	
millions	**2015**	2014
Commercial paper	**$ 250**	$ —
5.950% Senior Notes due 2016	**1,750**	1,750
6.375% Senior Notes due 2017	**2,000**	2,000
7.050% Debentures due 2018	**114**	114
Tangible equity units - senior amortizing notes due 2018	**85**	—
WES 2.600% Senior Notes due 2018	**350**	350
6.950% Senior Notes due 2019	**300**	300
8.700% Senior Notes due 2019	**600**	600
WES 5.375% Senior Notes due 2021	**500**	500
WES 4.000% Senior Notes due 2022	**670**	670
3.450% Senior Notes due 2024	**625**	625
6.950% Senior Notes due 2024	**650**	650
WES 3.950% Senior Notes due 2025	**500**	—
7.500% Debentures due 2026	**112**	112
7.000% Debentures due 2027	**54**	54
7.125% Debentures due 2027	**150**	150
6.625% Debentures due 2028	**17**	17
7.150% Debentures due 2028	**235**	235
7.200% Debentures due 2029	**135**	135
7.950% Debentures due 2029	**117**	117
7.500% Senior Notes due 2031	**900**	900
7.875% Senior Notes due 2031	**500**	500
Zero-Coupon Senior Notes due 2036	**2,360**	2,360
6.450% Senior Notes due 2036	**1,750**	1,750
7.950% Senior Notes due 2039	**325**	325
6.200% Senior Notes due 2040	**750**	750
4.500% Senior Notes due 2044	**625**	625
WES 5.450% Senior Notes due 2044	**400**	400
7.730% Debentures due 2096	**61**	61
7.500% Debentures due 2096	**78**	78
7.250% Debentures due 2096	**49**	49
WES revolving credit facility	**300**	510
Total borrowings at face value	**$ 17,312**	$ 16,687
Net unamortized discounts and premiums [(1)]	**(1,581)**	(1,616)
Total borrowings	**$ 15,731**	$ 15,071
Capital lease obligation	**20**	21
Less current portion of long-term debt	**33**	—
Total long-term debt [(2)]	**$ 15,718**	$ 15,092

(1) Unamortized discounts and premiums are amortized over the term of the related debt.

(2) The total long-term debt balance for WES was $2.7 billion at December 31, 2015, and $2.4 billion at December 31, 2014.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2015, 2014, AND 2013

11. Debt and Interest Expense (Continued)

In a 2006 private offering, Anadarko received $500 million of loan proceeds upon issuing the Zero-Coupon Senior Notes due 2036 (Zero Coupons). The Zero Coupons mature in 2036 and have an aggregate principal amount due at maturity of approximately $2.4 billion, reflecting a yield to maturity of 5.24%. The Zero Coupons can be put to the Company in October of each year, in whole or in part, for the then-accreted value of the outstanding Zero Coupons. The accreted value of the outstanding Zero Coupons was $806 million at December 31, 2015. Anadarko's Zero Coupons were classified as long-term debt on the Company's Consolidated Balance Sheet at December 31, 2015, as the Company has the ability and intent to refinance these obligations using long-term debt, should the put be exercised.

Anadarko's $1.750 billion 5.950% Senior Notes due September 2016 were classified as long-term debt on the Company's Consolidated Balance Sheet at December 31, 2015, as Anadarko intends to refinance these obligations prior to or at maturity with new long-term debt issuances or by using the $3.0 billion five-year senior unsecured revolving credit facility (Five-Year Facility).

Fair Value The Company uses a market approach to determine the fair value of its fixed-rate debt using observable market data, which results in a Level 2 fair-value measurement. The carrying amount of floating-rate debt approximates fair value as the interest rates are variable and reflective of market rates. The estimated fair value of the Company's total borrowings was $15.7 billion at December 31, 2015, and $17.4 billion at December 31, 2014.

Debt Activity The following summarizes the Company's debt activity:

millions	Carrying Value	Description
Balance at December 31, 2013	$ 13,557	
Issuances	101	WES 2.600% Senior Notes due 2018
	394	WES 5.450% Senior Notes due 2044
	624	3.450% Senior Notes due 2024
	621	4.500% Senior Notes due 2044
Borrowings	1,160	WES revolving credit facility
Repayments	(500)	7.625% Senior Notes due 2014
	(275)	5.750% Senior Notes due 2014
	(650)	WES revolving credit facility
Other, net	39	Amortization of debt discounts and premiums
Balance at December 31, 2014	$ 15,071	
Issuances	**494**	WES 3.950% Senior Notes due 2025
	101	Tangible equity units - senior amortizing notes
Borrowings	**1,500**	$5.0 billion revolving credit facility
	1,800	364-Day Facility
	400	WES revolving credit facility
	250	Commercial paper notes, net (1)
Repayments	**(1,500)**	$5.0 billion revolving credit facility
	(1,800)	364-Day Facility
	(610)	WES revolving credit facility
	(16)	Tangible equity units - senior amortizing notes
Other, net	**41**	Amortization of debt discounts and premiums
Balance at December 31, 2015	**$ 15,731**	

(1) Includes repayments of $(106) million related to commercial paper notes with maturities greater than 90 days.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2015, 2014, AND 2013

11. Debt and Interest Expense (Continued)

Anadarko Revolving Credit Facilities and Commercial Paper Program In June 2014, Anadarko entered into the Five-Year Facility and a $2.0 billion 364-day senior unsecured revolving credit facility (364-Day Facility). In January 2015, upon satisfaction of certain conditions, including the payment of the settlement related to the Tronox Adversary Proceeding, these facilities replaced the $5.0 billion Facility. In December 2015, the Company amended the Five-Year Facility to extend the maturity date to January 2021 and in January 2016, the Company replaced the 364-Day Facility with a new $2.0 billion 364-day senior unsecured revolving facility on identical terms that will mature in 2017.

Borrowings under the Five-Year Facility and the 364-Day Facility (collectivity, the Credit Facilities) generally bear interest under one of two rate options, at Anadarko's election, using either LIBOR (or Euro Interbank Offered Rate in the case of borrowings under the Five-Year Facility denominated in Euro) or an alternate base rate, in each case plus an applicable margin ranging from 0.00% to 1.65% for the Five-Year Facility and 0.00% to 1.675% for the 364-Day Facility. The applicable margin will vary depending on Anadarko's credit ratings.

The Credit Facilities contain certain customary affirmative and negative covenants, including a financial covenant requiring maintenance of a consolidated indebtedness to total capitalization ratio of no greater than 65% (excluding the effect of non-cash write-downs), and limitations on certain secured indebtedness, sale-and-leaseback transactions, and mergers and other fundamental changes. At December 31, 2015, the Company had no outstanding borrowings under the Credit Facilities and was in compliance with all covenants contained therein.

In January 2015, the Company initiated a commercial paper program, which allows a maximum of $3.0 billion of unsecured commercial paper notes and is supported by the Five-Year Facility. The maturities of the commercial paper notes vary, but may not exceed 397 days. The commercial paper notes are sold under customary terms in the commercial paper market and are issued either at a discounted price to their principal face value or will bear interest at varying interest rates on a fixed or floating basis. Such discounted price or interest amounts are dependent on market conditions and the ratings assigned to the commercial paper program by credit rating agencies at the time of issuance of the commercial paper notes. At December 31, 2015, the Company had $250 million of commercial paper notes outstanding at a weighted-average interest rate of 0.98%. Anadarko classified the outstanding commercial paper notes as long-term debt on the Company's Consolidated Balance Sheet at December 31, 2015, as the Company currently intends to refinance these obligations at maturity with additional commercial paper notes supported by the Five-Year Facility.

WES Borrowings In February 2014, WES amended and restated its then-existing $800 million senior unsecured revolving credit facility by entering into a five-year, $1.2 billion senior unsecured revolving credit facility maturing in February 2019 (RCF), which is expandable to a maximum of $1.5 billion. Borrowings under the RCF bear interest at LIBOR plus an applicable margin ranging from 0.975% to 1.45% depending on WES's credit rating, or the greatest of (i) rates at a margin above the one-month LIBOR, (ii) the federal funds rate, or (iii) prime rates offered by certain designated banks. At December 31, 2015, WES was in compliance with all covenants contained in its RCF, had outstanding borrowings under its RCF of $300 million at an interest rate of 1.73%, and had available borrowing capacity of approximately $894 million ($1.2 billion capacity, less $300 million of outstanding borrowings and $6 million of outstanding letters of credit).

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2015, 2014, AND 2013

11. Debt and Interest Expense (Continued)

Scheduled Maturities Total principal amount of debt maturities for the five years ending December 31, 2020, excluding the potential repayment of the outstanding Zero Coupons that may be put by the holders to the Company annually, were as follows:

millions	**Principal Amount of Debt Maturities**
2016	$ 2,033
2017	2,034
2018	482
2019	1,200
2020	—

Interest Expense The following summarizes interest expense for the years ended December 31:

millions	**2015**	2014	2013
Debt and other	**$ 989**	$ 973	$ 949
Capitalized interest	**(164)**	(201)	(263)
Total interest expense	**$ 825**	$ 772	$ 686

12. Income Taxes

The following summarizes components of income tax expense (benefit) for the years ended December 31:

millions	**2015**	2014	2013
Current			
Federal	**$ (177)**	$ 188	$ 113
State	**(18)**	2	42
Foreign	**495**	1,574	873
	300	1,764	1,028
Deferred			
Federal	**(2,929)**	(389)	94
State	**(145)**	27	(9)
Foreign	**(103)**	215	52
	(3,177)	(147)	137
Total income tax expense (benefit)	**$ (2,877)**	$ 1,617	$ 1,165

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2015, 2014, AND 2013

12. Income Taxes (Continued)

Total income taxes differed from the amounts computed by applying the U.S. federal statutory income tax rate to income (loss) before income taxes. The following summarizes the sources of these differences for the years ended December 31:

millions except percentages	**2015**	2014	2013
Income (loss) before income taxes			
Domestic	**$ (9,155)**	$ (3,564)	$ 428
Foreign	**(534)**	3,618	1,678
Total	**$ (9,689)**	$ 54	$ 2,106
U.S. federal statutory tax rate	**35%**	35%	35%
Tax computed at the U.S. federal statutory rate	**$ (3,391)**	$ 19	$ 737
Adjustments resulting from			
State income taxes (net of federal income tax benefit)	**(81)**	(11)	23
Tax impact from foreign operations	**299**	62	204
Non-deductible Algerian exceptional profits tax	**102**	193	144
Net changes in uncertain tax positions	**54**	1,427	(29)
Deferred tax adjustments	**10**	15	76
Non-deductible Tronox-related contingent loss	**—**	(36)	36
(Income) loss attributable to noncontrolling interests	**42**	(66)	(48)
Non-deductible Deepwater Horizon costs	**26**	32	—
Federal manufacturing deduction	**—**	(27)	—
Dispositions of non-deductible goodwill	**62**	21	—
Other, net	**—**	(12)	22
Total income tax expense (benefit)	**$ (2,877)**	$ 1,617	$ 1,165
Effective tax rate	**30%**	2,994%	55%

The following summarizes components of total deferred taxes at December 31:

millions	**2015**	2014
Federal	**$ (4,721)**	$ (7,649)
State, net of federal	**(248)**	(341)
Foreign	**(431)**	(537)
Total deferred taxes	**$ (5,400)**	$ (8,527)

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2015, 2014, AND 2013

12. Income Taxes (Continued)

The following summarizes tax effects of temporary differences that give rise to significant portions of the deferred tax assets (liabilities) at December 31:

millions	**2015**	2014
Deferred tax liabilities		
Oil and gas exploration and development operations	**$ (5,643)**	$ (8,418)
Midstream and other depreciable properties	**(1,049)**	(1,611)
Mineral operations	**(492)**	(412)
Other	**(470)**	(351)
Gross long-term deferred tax liabilities	**(7,654)**	(10,792)
Deferred tax assets		
Foreign and state net operating loss carryforwards	**586**	558
U.S. foreign tax credit carryforwards	**1,254**	166
Compensation and benefit plans	**615**	701
Mark to market on derivatives	**441**	354
Settlement agreement related to the Tronox Adversary Proceeding	**—**	590
Other	**761**	760
Gross long-term deferred tax assets	**3,657**	3,129
Valuation allowances on deferred tax assets not expected to be realized	**(1,403)**	(864)
Net long-term deferred tax assets	**2,254**	2,265
Total deferred taxes	**$ (5,400)**	$ (8,527)

The valuation allowance primarily relates to U.S. foreign tax credit carryforwards and foreign and state net operating loss carryforwards, which reduces the Company's net deferred tax asset to an amount that will more likely than not be realized within the carryforward period.

The following summarizes changes in the balance of valuation allowances on deferred tax assets:

millions	**2015**	2014	2013
Balance at January 1	**$ (864)**	$ (818)	$ (922)
Changes due to U.S. foreign tax credits	**(384)**	11	58
Changes due to foreign and state net operating loss carryforwards	**10**	64	(57)
Changes due to foreign capitalized costs	**(165)**	(121)	103
Balance at December 31	**$ (1,403)**	$ (864)	$ (818)

Tax carryforwards available for use on future income tax returns, prior to valuation allowance, at December 31, 2015, were as follows:

millions	**Domestic**	**Foreign**	**Expiration**
Net operating loss—foreign	$ —	$ 1,264	2016 - Indefinite
Net operating loss—state	$ 4,762	$ —	2016-2035
Foreign tax credits	$ 1,254	$ —	2023-2026
Texas margins tax credit	$ 33	$ —	2026

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2015, 2014, AND 2013

12. Income Taxes (Continued)

The following summarizes taxes receivable (payable) related to income tax expense (benefit) at December 31:

millions **Balance Sheet Classification**	**2015**	2014
Income taxes receivable		
Accounts receivable—other	**$ 1,046**	$ 93
Other assets	**61**	35
	1,107	128
Income taxes (payable)		
Accrued expense	**(9)**	(152)
Total net income taxes receivable (payable)	**$ 1,098**	$ (24)

Changes in the balance of unrecognized tax benefits excluding interest and penalties on uncertain tax positions were as follows:

	Assets (Liabilities)		
millions	**2015**	2014	2013
Balance at January 1	**$ (1,687)**	$ (147)	$ (46)
Increases related to prior-year tax positions	**(99)**	(11)	(54)
Decreases related to prior-year tax positions	**89**	39	3
Increases related to current-year tax positions	**(263)**	(1,568)	(72)
Settlements	**180**	—	5
Lapse of statute of limitations	**—**	—	17
Balance at December 31	**$ (1,780)**	$ (1,687)	$ (147)

Included in the 2015 ending balance of unrecognized tax benefits presented above are potential benefits of $1.756 billion, of which, if recognized, $1.337 billion would affect the effective tax rate on income, and $395 million would be in the form of foreign tax credits and net operating loss carryforwards that would be offset with a full valuation allowance. Also included in the 2015 ending balance are benefits of $24 million related to tax positions for which the ultimate deductibility is highly certain, but the timing of such deductibility is uncertain.

As of December 31, 2015, the Company had recorded a total tax benefit of $576 million related to the Tronox-related contingent liability. This benefit is net of a $1.3 billion uncertain tax position due to the uncertainty related to the deductibility of the settlement payment. The Company is a participant in the U.S. Internal Revenue Service's (IRS) Compliance Assurance Process for the 2015 tax year and has regular discussions with the IRS concerning the Company's tax position. Depending on the outcome of such discussions, it is reasonably possible that the amount of the uncertain tax position related to the settlement could change, perhaps materially. See *Note 15—Contingencies—Tronox Litigation*.

Income tax audits and the Company's acquisition and divestiture activity have given rise to tax disputes in U.S. and foreign jurisdictions. See *Note 15—Contingencies—Other Litigation.* Over the next 12 months, it is reasonably possible that the total amount of unrecognized tax benefits could decrease by $400 million to $410 million due to settlements with taxing authorities or lapse in statutes of limitation. The majority of the possible decrease relates to foreign tax credit amounts that would be offset with a full valuation allowance and would have no effect on the effective tax rate. With the exception of the deductibility of the Tronox settlement payment discussed above, management does not believe that the final resolution of outstanding tax audits and litigation will have a material adverse effect on the Company's consolidated financial condition, results of operations, or cash flows.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2015, 2014, AND 2013

12. Income Taxes (Continued)

The Company had accrued approximately $11 million of interest related to uncertain tax positions at December 31, 2015, and $9 million at December 31, 2014. The Company recognized interest and penalties in income tax expense (benefit) of $2 million during 2015 and $1 million during 2014.

Anadarko is subject to audit by tax authorities in the U.S. federal, state, and local tax jurisdictions as well as in various foreign jurisdictions. The following lists the tax years subject to examination by major tax jurisdiction:

	Tax Years
United States	2008-2015
Algeria	2012-2015
Ghana	2006-2015

13. Asset Retirement Obligations

The majority of Anadarko's AROs relate to the plugging of wells and the related abandonment of oil and gas properties. Revisions in estimated liabilities during the period relate primarily to changes in estimates of asset retirement costs and include, but are not limited to, revisions of estimated inflation rates, changes in property lives, and the expected timing of settlement. The following summarizes changes in the Company's AROs:

millions	**2015**	2014
Carrying amount of asset retirement obligations at January 1	**$ 2,053**	$ 2,022
Liabilities incurred	**104**	119
Property dispositions	**(108)**	(70)
Liabilities settled	**(298)**	(443)
Accretion expense	**102**	93
Revisions in estimated liabilities	**206**	332
Carrying amount of asset retirement obligations at December 31	**$ 2,059**	$ 2,053

**ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2015, 2014, AND 2013**

14. Commitments

Operating Leases At December 31, 2015, the Company had $1.8 billion in long-term drilling rig commitments that satisfy operating lease criteria. The Company also had $329 million of various commitments under non-cancelable operating lease agreements for production platforms and equipment, buildings, facilities, compressors, and aircraft. These operating leases expire at various dates through 2026. Certain of these operating leases contain residual value guarantees at the end of the lease term, totaling $81 million at December 31, 2015. No liability has been accrued for residual value guarantees. In addition, these operating leases include options to purchase the leased property during or at the end of the lease term for the fair market value or other specified amount at that time. The following summarizes future minimum lease payments under operating leases at December 31, 2015:

millions		
2016	$	806
2017		604
2018		352
2019		228
2020		86
Later years		41
Total future minimum lease payments	$	2,117

Anadarko has entered into various agreements to secure drilling rigs necessary to support the execution of its drilling plans over the next several years. The table of future minimum lease payments above includes $1.7 billion related to five offshore drilling vessels and $98 million related to certain contracts for U.S. onshore drilling rigs. Lease payments associated with the drilling of exploratory wells and development wells net of amounts billed to partners will initially be capitalized as a component of oil and gas properties, and either depreciated or impaired in future periods or written off as exploration expense.

Total rent expense, net of sublease income and amounts capitalized, amounted to $77 million in 2015, $85 million in 2014, and $119 million in 2013. Total rent expense includes contingent rent expense related to transportation and processing fees of $17 million in 2015, $22 million in 2014, and $24 million in 2013.

Other Commitments In the normal course of business, the Company enters into other contractual agreements for processing, treating, transportation, and storage of oil, natural gas, and NGLs as well as for other oil and gas activities. These agreements expire at various dates through 2036. At December 31, 2015, aggregate future payments under these contracts totaled $10.1 billion, of which $1.9 billion is expected to be paid in 2016, $1.7 billion in 2017, $1.3 billion in 2018, $1.2 billion in 2019, $1.1 billion in 2020, and $2.9 billion thereafter.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2015, 2014, AND 2013

15. Contingencies

Litigation The Company is a defendant in a number of lawsuits, is involved in governmental proceedings, and is subject to regulatory controls arising in the ordinary course of business, including personal injury claims; property damage claims; title disputes; tax disputes; royalty claims; contract claims; contamination claims relating to oil and gas exploration, production, transportation, and processing; and environmental claims, including claims involving assets owned by acquired companies and claims involving assets previously sold to third parties and no longer a part of the Company's current operations. The Company's Consolidated Balance Sheets include liabilities of $269 million at December 31, 2015, and $5.3 billion at December 31, 2014, for litigation-related contingencies. Anadarko is also subject to various environmental-remediation and reclamation obligations arising from federal, state, and local laws and regulations. While the ultimate outcome and impact on the Company cannot be predicted with certainty, after consideration of recorded expense and liability accruals, management believes that the resolution of pending proceedings will not have a material adverse effect on the Company's consolidated financial condition, results of operations, or cash flows.

Deepwater Horizon Events In April 2010, the Macondo well in the Gulf of Mexico blew out and an explosion occurred on the *Deepwater Horizon* drilling rig, resulting in an oil spill. The well was operated by BP Exploration and Production Inc. (BP) and Anadarko held a 25% nonoperated interest. In October 2011, the Company and BP entered into a settlement agreement, mutual releases, and agreement to indemnify relating to the Deepwater Horizon events (Settlement Agreement), under which the Company paid $4.0 billion in cash and transferred its interest in the Macondo well and the Mississippi Canyon Block 252 (Lease) to BP. Pursuant to the Settlement Agreement, the Company is fully indemnified by BP against all claims, causes of action, losses, costs, expenses, liabilities, damages, or judgments of any kind arising out of the Deepwater Horizon events, related damage claims arising under the Oil Pollution Act of 1990 (OPA), claims for natural resource damages (NRD) and assessment costs, and any claims arising under the Operating Agreement with BP (OA). This indemnification is guaranteed by BP Corporation North America Inc. (BPCNA) and, in the event that the net worth of BPCNA declines below an agreed-upon amount, BP p.l.c. has agreed to become the sole guarantor. Under the Settlement Agreement, BP does not indemnify the Company against penalties and fines, punitive damages, shareholder derivative or securities laws claims, or certain other claims.

Numerous Deepwater Horizon event-related civil lawsuits have been filed against BP and other parties, including the Company by, among others, fishing, boating, and shrimping enterprises and industry groups; restaurants; commercial and residential property owners; certain rig workers or their families; the States of Alabama, Louisiana, Texas, and Mississippi, and several of their political subdivisions; the U.S. Department of Justice (DOJ); environmental non-governmental organizations; and certain Mexican states. Many of the lawsuits filed assert various claims of negligence, gross negligence, and violations of several federal and state laws and regulations, including, among others, OPA; the Comprehensive Environmental Response, Compensation, and Liability Act; the Clean Air Act; the Clean Water Act (CWA); and the Endangered Species Act; or challenge existing permits for operations in the Gulf of Mexico. Generally, the plaintiffs seek actual damages, punitive damages, declaratory judgment, and/or injunctive relief. This litigation has been consolidated into a federal Multidistrict Litigation (MDL) action pending before Judge Carl Barbier in the U.S. District Court for the Eastern District of Louisiana in New Orleans, Louisiana (Louisiana District Court).

In July 2015, BP announced a settlement agreement in principle with the DOJ and certain states and local government entities regarding essentially all of the outstanding claims against BP related to the Deepwater Horizon event (BP Settlement) and, in October 2015, lodged a proposed consent decree with the Louisiana District Court. A hearing related to the consent decree is currently scheduled for March 2016.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2015, 2014, AND 2013

15. Contingencies (Continued)

Liability Accrual Below is a discussion of the Company's current analysis, under applicable accounting guidance, of its potential liability for (i) amounts under the OA (OA Liabilities), (ii) OPA-related environmental costs, and (iii) other contingent liabilities. Applicable accounting guidance requires the Company to accrue a liability if both (a) it is probable that a liability has been incurred and (b) the amount of that liability can be reasonably estimated.

The Company is fully indemnified by BP against OPA damage claims, NRD claims and assessment costs, and other potential liabilities. The Company may be required to recognize a liability for these amounts in advance of or in connection with recognizing a receivable from BP for the related indemnity payment. In all circumstances, however, the Company expects that any additional indemnified liability that may be recognized by the Company will be subsequently recovered from BP itself or through the guarantees of BPCNA or BP p.l.c. The Company has not recorded a liability for any costs that are subject to indemnification by BP.

OA Liabilities Pursuant to the Settlement Agreement, all amounts deemed by BP to have been due under the OA, as well as all future amounts that otherwise would be invoiced to Anadarko under the OA, have been satisfied.

OPA-Related Environmental Costs BP, Anadarko, and other parties, including parties that do not own an interest in the Lease, such as the drilling contractor, have received correspondence from the U.S. Coast Guard (USCG) referencing their identification as a "responsible party or guarantor" (RP) under OPA. Under OPA, RPs, including Anadarko, may be jointly and severally liable for costs of well control, spill response, and containment and removal of hydrocarbons as well as other costs and damage claims related to the spill and spill cleanup. The USCG's identification of Anadarko as an RP arises as a result of Anadarko's status as a co-lessee in the Lease.

Under accounting guidance applicable to environmental liabilities, a liability is presumed probable if the entity is both identified as an RP and associated with the environmental event. The Company's co-lessee status in the Lease at the time of the event and the subsequent identification and treatment of the Company as an RP satisfies these standards and therefore establishes the presumption that the Company's potential environmental liabilities related to the Deepwater Horizon events are probable.

As BP funds OPA-related environmental costs, any potential joint and several liability for these costs is satisfied for all RPs, including Anadarko. This bears significance in that once these costs are funded by BP, such costs are no longer analyzed as OPA-related environmental costs, but instead are analyzed as OA Liabilities. As discussed above, Anadarko has settled its OA Liabilities with BP. Thus, potential liability to the Company for OPA-related environmental costs can arise only where BP does not, or otherwise is unable to, fund all of the OPA-related environmental costs. Under this scenario, the joint and several nature of the liability for these costs could cause the Company to recognize a liability for OPA-related environmental costs. However, all liability relating to OPA-related environmental costs should be resolved as part of the BP Settlement, provided that the consent decree is ultimately approved by the Louisiana District Court. Additionally, in the event the consent decree is not approved by the Louisiana District Court, the Company is fully indemnified by BP against these costs (including guarantees by BPCNA or BP p.l.c.).

Allocable Share of Gross OPA-Related Environmental Costs Under applicable accounting guidance, the Company is required to estimate its allocable share of gross OPA-related environmental costs. To date, BP has paid all Deepwater Horizon event-related costs, which satisfies the Company's potential liability for these costs. Additionally, BP has entered into the BP Settlement Agreement to resolve all liability associated with these costs. Based on the BP Settlement Agreement, BP's stated intent to continue funding these costs, the Company's assessment of BP's financial ability to continue funding these costs, and the impact of BP's settlements with both of its OA partners, the Company believes the likelihood of BP not continuing to satisfy these claims to be remote. Accordingly, the Company considers zero to be its allocable share of gross OPA-related environmental costs and, consistent with applicable accounting guidance, has not recorded a liability for these amounts.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2015, 2014, AND 2013

15. Contingencies (Continued)

Penalties and Fines These costs include amounts that may be assessed as a result of potential civil and/or criminal penalties under various federal, state, and/or local statutes and/or regulations as a result of the Deepwater Horizon events, including, for example, the CWA, the Outer Continental Shelf Lands Act, the Migratory Bird Treaty Act, and possibly other federal, state, and local laws. The foregoing does not represent an exhaustive list of statutes and regulations that potentially could trigger a penalty or fine assessment against the Company. In December 2010, the DOJ on behalf of the United States, filed a civil lawsuit in the Louisiana District Court against several parties, including the Company, seeking an assessment of civil penalties under the CWA in an amount to be determined by the Louisiana District Court. In an effort to resolve this matter, the Company made a settlement offer to the DOJ in July 2014 and had a contingent liability of $90 million recorded as of December 31, 2014. After previously finding that Anadarko, as a nonoperating investor in the Macondo well, was not culpable with respect to the Deepwater Horizon events, the Louisiana District Court found Anadarko liable for civil penalties under Section 311 of the CWA as a working-interest owner in the Macondo well and entered a judgment of $159.5 million in December 2015. The Company recorded an additional contingent liability during 2015 for $69.5 million, for a total liability of $159.5 million at December 31, 2015. The deadline for an appeal of the decision was February 16, 2016. The parties did not appeal the decision; accordingly, the Company expects to pay the penalty in the first quarter of 2016.

As discussed below, numerous Deepwater Horizon event-related civil lawsuits have been filed against BP and other parties, including the Company. Certain state and local governments appealed, or provided indication of a likely appeal of, the Louisiana District Court's decision that only federal law, and not state law, applies to Deepwater Horizon event-related claims. These appeals should be dismissed as part of the BP Settlement, provided that the consent decree is ultimately approved by the Louisiana District Court. In the event the consent decree is not approved by the Louisiana District Court and any such appeal proceeds and is successful, state and/or local laws and regulations could become sources of penalties or fines against the Company.

Natural Resource Damages This category includes future damage claims that may be made by federal and/or state natural resource trustee agencies at the completion of injury assessments and restoration planning. Natural resources generally include land, fish, water, air, wildlife, and other such resources belonging to, managed by, held in trust by, or otherwise controlled by, the federal, state, or local government. The NRD assessment process is led by various federal agencies and affected states. Referred to as the "Co-Trustees," these entities continue to conduct injury assessment and restoration planning. NRD claims are generally sought after the damage assessment and restoration planning is completed, which may take several years. Thus, the Company remains unable to reasonably estimate the magnitude of any NRD claim. However, all NRD claims should be dismissed as part of the BP Settlement, provided that the consent decree is ultimately approved by the Louisiana District Court. In the event the Louisiana District Court does not approve the consent decree, the Company anticipates that BP will satisfy any NRD claim, which eliminates any potential liability to Anadarko for such costs. In the event any NRD damage claim is made directly against Anadarko, the Company is fully indemnified by BP against such claims (including guarantees by BPCNA or BP p.l.c.).

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2015, 2014, AND 2013

15. Contingencies (Continued)

Civil Litigation Damage Claims As discussed above, numerous Deepwater Horizon event-related civil lawsuits have been filed against BP and other parties, including the Company. Generally, the plaintiffs are seeking actual damages, punitive damages, declaratory judgment, and/or injunctive relief. However, all claims relating to this MDL action should be dismissed as part of the BP Settlement, provided that the consent decree is ultimately approved by the Louisiana District Court. Additionally, in the event the consent decree is not approved by the Louisiana District Court, the Company, pursuant to the Settlement Agreement, is fully indemnified by BP against losses arising as a result of claims for damages, irrespective of whether such claims are based on federal (including OPA) or state law.

Remaining Liability Outlook It is possible that the Company may recognize additional Deepwater Horizon event-related liabilities for potential penalties and fines and certain royalty claims not covered by the indemnification provisions of the Settlement Agreement.

Tronox Litigation On November 28, 2005, Tronox Incorporated (Tronox), at the time a subsidiary of Kerr-McGee Corporation, completed an initial public offering (IPO) and was subsequently spun-off from Kerr-McGee Corporation. In August 2006, Anadarko acquired all of the stock of Kerr-McGee Corporation. In January 2009, Tronox and certain of Tronox's subsidiaries filed voluntary petitions for relief under Chapter 11 of the U.S. Bankruptcy Code in the U.S. Bankruptcy Court for the Southern District of New York (Bankruptcy Court), which is the court that presided over the Adversary Proceeding (defined below). In May 2009, Tronox and certain of its affiliates filed a lawsuit against Anadarko and Kerr-McGee Corporation and certain of its subsidiaries (collectively, Kerr-McGee) asserting several claims, including claims for actual and constructive fraudulent conveyance (Adversary Proceeding). Tronox alleged, among other things, that it was insolvent or undercapitalized at the date of its IPO and sought, among other things, to recover damages in excess of $18.85 billion from Kerr-McGee and Anadarko as well as interest and attorneys' fees and costs. In accordance with Tronox's Bankruptcy Court-approved Plan of Reorganization (Plan), the Adversary Proceeding was pursued by a litigation trust (Litigation Trust). Pursuant to the Plan, the Litigation Trust was "deemed substituted" for the Tronox plaintiffs in the Adversary Proceeding. For purposes of this Form 10-K, references to "Tronox" after February 2011 refer to the Litigation Trust.

The U.S. government intervened in the Adversary Proceeding, and in May 2009 asserted separate claims against Anadarko and Kerr-McGee under the Federal Debt Collection Procedures Act (FDCPA Complaint). The Litigation Trust and the U.S. government agreed that the recovery of damages under the Adversary Proceeding, if any, would cover both the Adversary Proceeding and the FDCPA Complaint.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2015, 2014, AND 2013

15. Contingencies (Continued)

Liability Accrual On April 3, 2014, Anadarko and Kerr-McGee entered into a settlement agreement with the Litigation Trust and the U.S. government (in its capacity as plaintiff-intervenor and acting for and on behalf of certain U.S. government agencies) to resolve all claims asserted in the Adversary Proceeding and FDCPA Complaint for $5.15 billion, which represents principal of approximately $3.98 billion plus 6% interest from the filing of the Adversary Proceeding on May 12, 2009, through April 3, 2014. In addition, the Company agreed to pay interest on the above amount from April 3, 2014, through the payment of the settlement, with an annual interest rate of 1.5% for the first 180 days and 1.5% plus the one-month LIBOR thereafter. Under the terms of the settlement agreement, the Litigation Trust, Anadarko, and Kerr-McGee agreed to mutually release all claims that were or could have been asserted in the Adversary Proceeding. The U.S. government (representing federal agencies that filed claims in the Tronox bankruptcy), Anadarko, and Kerr-McGee also provided covenants not to sue each other with respect to certain claims and causes of action. The U.S. government also provided contribution protection from third-party claims seeking reimbursement from Anadarko and certain of its affiliates for the sites identified in the settlement agreement. In January 2015, the Company paid $5.2 billion after the settlement agreement became effective.

Anadarko recognized Tronox-related contingent losses of $850 million in the fourth quarter of 2013 and $4.3 billion in the first quarter of 2014. In addition, Anadarko recognized settlement-related interest expense, included in Tronox-related contingent loss in the Company's Consolidated Statements of Income, of $60 million during 2014 and $5 million during the first quarter of 2015. At December 31, 2015, there was no Tronox-related contingent liability on the Company's Consolidated Balance Sheet. For information on the tax effects of the Tronox settlement agreement, see *Note 12—Income Taxes*.

Other Litigation In December 2008, Anadarko sold its interest in the Peregrino heavy-oil field offshore Brazil. The Company is currently litigating a dispute with the Brazilian tax authorities regarding the tax rate applicable to the transaction. In December 2008, the Company deposited the amount of tax originally in dispute in a Brazilian real-denominated judicially-controlled Brazilian bank account pending final resolution of the matter. At December 31, 2015, the deposit of $86 million is included in other assets on the Company's Consolidated Balance Sheet.

In July 2009, the lower judicial court ruled in favor of the Brazilian tax authorities. The Company appealed this decision to the Brazilian Regional courts, which upheld the lower court's ruling in favor of the Brazilian tax authorities in December 2011. In April 2012, the Company filed simultaneous appeals to the Brazilian Superior Court and the Brazilian Supreme Court. The Brazilian Superior Court and the Brazilian Supreme Court have agreed to hear the case and the Company currently is awaiting the setting of initial hearing dates.

In August 2013, following a determination by an administrative court in a related matter that the amount of tax in dispute was not calculated properly, the Company filed a petition requesting the withdrawal of a portion of the judicial deposit to the extent it exceeds the amount of tax currently in dispute and any interest on such excess amount. In April 2015, the Company's petition was denied. The Company appealed this decision. The appeal was denied in November 2015.

The Company believes that it will more likely than not prevail in the Brazilian Superior Court and the Brazilian Supreme Court. Therefore, no tax liability has been recorded for Peregrino divestiture-related litigation at December 31, 2015. The Company continues to vigorously defend its position in Brazilian courts.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2015, 2014, AND 2013

15. Contingencies (Continued)

Guarantees and Indemnifications The Company provides certain indemnifications in relation to asset dispositions. These indemnifications typically relate to disputes, litigation, or tax matters existing at the date of disposition. In 2013, as a result of a Chapter 11 bankruptcy declaration by a third party, the Department of the Interior ordered Anadarko to perform the decommissioning of a production facility and related wells, which were previously sold to the third party. During 2013, the Company accrued costs of $117 million to decommission the production facility and related wells, reported in other (income) expense, net in the Company's Consolidated Statement of Income. During each of the years ended December 31, 2015 and 2014, the Company recognized a $22 million increase in the estimated decommissioning costs. Anadarko completed decommissioning of the production facility in 2014 and expects to complete decommissioning of the wells in 2016. Decommissioning obligations of $116 million at December 31, 2015, and $114 million at December 31, 2014, were included in accrued expenses on the Company's Consolidated Balance Sheets. Actual costs may vary from this estimate; however, the Company does not believe that any such change will materially impact its financial condition, results of operations, or cash flows.

Environmental Matters Anadarko is also subject to various environmental-remediation and reclamation obligations arising from federal, state, and local laws and regulations. The Company's Consolidated Balance Sheets include liabilities for remediation and reclamation obligations of $145 million at December 31, 2015, and $126 million at December 31, 2014. The current portion of these amounts was included in accounts payable and the long-term portion of these amounts was included in other long-term liabilities—other on the Company's Consolidated Balance Sheets. The Company continually monitors remediation and reclamation processes and adjusts its liability for these obligations as necessary.

The Company is one of numerous parties previously notified by the California Department of Toxic Substances Control (DTSC) that, as a result of a prior acquisition, it is a potentially responsible party with respect to a landfill located in West Covina, California. While no agreement is in place with the DTSC, the Company recorded a $50 million restoration liability in 2013 with respect to the site, representing the current estimated obligation, which is included in the Company's liability balance at December 31, 2015. The Company could incur additional obligations if any of the potentially responsible parties are ultimately not able to fund their allocated share of the costs or if the DTSC requires a more costly remedial approach. It is possible that the Company's current estimate of probable loss related to this matter could change, perhaps materially, in the future.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2015, 2014, AND 2013

16. Pension Plans, Other Postretirement Benefits, and Defined-Contribution Plans

The Company has contributory and non-contributory defined-benefit pension plans, which include both qualified and supplemental plans. The Company also provides certain health care and life insurance benefits for certain retired employees. Retiree health care benefits are funded by contributions from the retiree, and in certain circumstances, contributions from the Company. The Company's retiree life insurance plan is non-contributory.

The following sets forth changes in the benefit obligations and fair value of plan assets for the Company's pension and other postretirement benefit plans for the years ended December 31, 2015 and 2014, as well as the funded status of the plans and amounts recognized in the financial statements at December 31, 2015 and 2014:

	Pension Benefits		Other Benefits	
millions	**2015**	2014	**2015**	2014
Change in benefit obligation				
Benefit obligation at beginning of year	**$ 2,528**	$ 2,158	**$ 373**	$ 294
Service cost	**118**	99	**9**	7
Interest cost	**101**	99	**15**	15
Plan amendments	**—**	—	**(89)**	—
Actuarial (gain) loss	**(115)**	337	**(27)**	72
Participant contributions	**—**	1	**5**	4
Benefit payments	**(194)**	(159)	**(20)**	(19)
Foreign-currency exchange-rate changes	**(7)**	(7)	**—**	—
Benefit obligation at end of year (1)	**$ 2,431**	$ 2,528	**$ 266**	$ 373
Change in plan assets				
Fair value of plan assets at beginning of year	**$ 1,818**	$ 1,754	**$ —**	$ —
Actual return on plan assets	**16**	111	**—**	—
Employer contributions	**43**	121	**15**	15
Participant contributions	**—**	1	**5**	4
Benefit payments	**(194)**	(159)	**(20)**	(19)
Foreign-currency exchange-rate changes	**(9)**	(10)	**—**	—
Fair value of plan assets at end of year	**$ 1,674**	$ 1,818	**$ —**	$ —
Funded status of the plans at end of year	**$ (757)**	$ (710)	**$ (266)**	$ (373)
Total recognized amounts in the balance sheet consist of				
Other assets	**$ 41**	$ 41	**$ —**	$ —
Accrued expenses	**(24)**	(24)	**(16)**	(15)
Other long-term liabilities—other	**(774)**	(727)	**(250)**	(358)
Total	**$ (757)**	$ (710)	**$ (266)**	$ (373)
Total recognized amounts in accumulated other comprehensive income consist of				
Prior service cost (credit)	**$ (1)**	$ (1)	**$ (84)**	$ 2
Net actuarial (gain) loss	**655**	740	**(25)**	1
Total	**$ 654**	$ 739	**$ (109)**	$ 3

(1) The accumulated benefit obligation for all defined-benefit pension plans was $2.1 billion at both December 31, 2015 and December 31, 2014.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2015, 2014, AND 2013

16. Pension Plans, Other Postretirement Benefits, and Defined-Contribution Plans (Continued)

The following summarizes the Company's defined-benefit pension plans with accumulated benefit obligations in excess of plan assets for the years ended December 31:

millions	**2015**	2014
Projected benefit obligation	**$ 2,309**	$ 2,403
Accumulated benefit obligation	**1,954**	2,024
Fair value of plan assets	**1,511**	1,652

The following summarizes the Company's pension and other postretirement benefit cost and amounts recognized in other comprehensive income (before tax benefit) for the years ended December 31:

	Pension Benefits			**Other Benefits**		
millions	**2015**	2014	2013	**2015**	2014	2013
Components of net periodic benefit cost						
Service cost	**$ 118**	$ 99	$ 85	**$ 9**	$ 7	$ 9
Interest cost	**101**	99	78	**15**	15	14
Expected return on plan assets	**(109)**	(106)	(91)	**—**	—	—
Amortization of net actuarial loss (gain)	**52**	34	118	**—**	(7)	—
Amortization of net prior service cost (credit)	**—**	—	—	**(4)**	—	1
Settlement loss	**11**	—	14	**—**	—	—
Net periodic benefit cost	**$ 173**	$ 126	$ 204	**$ 20**	$ 15	$ 24
Amounts recognized in other comprehensive income (expense)						
Net actuarial gain (loss)	**$ 22**	$ (333)	$ 342	**$ 27**	$ (72)	$ 74
Amortization of net actuarial (gain) loss	**52**	34	118	**—**	(7)	—
Net prior service (cost) credit	**—**	—	—	**89**	—	—
Amortization of net prior service cost (credit)	**—**	—	—	**(4)**	—	1
Settlement loss	**11**	—	14	**—**	—	—
Total amounts recognized in other comprehensive income (expense)	**$ 85**	$ (299)	$ 474	**$ 112**	$ (79)	$ 75

The Company amortizes prior service costs (credits) on a straight-line basis over the average remaining service period of employees expected to receive benefits under each plan. Actuarial gains and losses that exceed 10% of the greater of the projected benefit obligation and the market-related value of assets are amortized over the average remaining service period of participating employees expected to receive benefits under each plan. In 2016, an estimated $34 million of net actuarial loss and $27 million of net prior service credit for the pension and other postretirement plans will be amortized from accumulated other comprehensive income into net periodic benefit cost.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2015, 2014, AND 2013

16. Pension Plans, Other Postretirement Benefits, and Defined-Contribution Plans (Continued)

Defined-benefit plan obligations and costs are actuarially determined, incorporating the use of various assumptions. Critical assumptions for pension and other postretirement plans include the discount rate, the expected long-term rate of return on plan assets (for funded pension plans), the rate of future compensation increases, and the health care cost trend rate or inflation (for postretirement plans). Other assumptions involve demographic factors such as retirement age, mortality, and turnover. The Company evaluates and updates its actuarial assumptions at least annually.

Accumulated and projected benefit obligations are measured as the present value of future cash payments. The Company discounts those cash payments using a discount rate that reflects the weighted average of market-observed yields for select high-quality (AA-rated) fixed-income securities with cash flows that correspond to the expected amounts and timing of benefit payments. The discount-rate assumption used by the Company represents an estimate of the interest rate at which the pension and other postretirement benefit obligations could effectively be settled on the measurement date. Assumed rates of compensation increases for active participants vary by age group, with the resulting weighted-average assumed rate (weighted by the plan-level benefit obligation) provided in the preceding table.

The following summarizes the weighted-average assumptions used by the Company in determining the pension and other postretirement benefit obligations and net periodic benefit cost for the years ended December 31:

	Pension Benefits			Other Benefits		
	2015	2014	2013	**2015**	2014	2013
Benefit obligation assumptions						
Discount rate	**4.50%**	4.00%	4.75%	**5.00%**	4.25%	5.25%
Rates of increase in compensation levels	**5.25%**	5.25%	5.00%	**5.50%**	5.25%	5.25%
Net periodic benefit cost assumptions						
Discount rate	**4.00%**	4.75%	3.50%	**4.25%**	5.25%	4.00%
Long-term rate of return on plan assets	**6.75%**	6.75%	7.00%	**N/A**	N/A	N/A
Rates of increase in compensation levels	**5.25%**	5.00%	4.50%	**5.25%**	5.25%	4.50%

An annual rate of increase indexed to the Consumer Price Index (CPI) of 1.75% was assumed for purposes of measuring the other postretirement benefit obligation at December 31, 2015, due to a plan amendment effective in 2016 that changed the Company's annual benefit payments to a per-participant fixed amount, subject to annual escalation based upon CPI. An 8.00% annual rate of increase in the per-capita cost of covered health care benefits for the next year was assumed for purposes of measuring other postretirement benefit obligations at December 31, 2014.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2015, 2014, AND 2013

16. Pension Plans, Other Postretirement Benefits, and Defined-Contribution Plans (Continued)

Plan Assets

Investment Policies and Strategies The Company has adopted a balanced, diversified investment strategy, with the intent of maximizing returns without exposure to undue risk. Investments are typically made through investment managers across several investment categories (domestic equity securities, international equity securities, fixed-income securities, real estate, hedge funds, and private equity), with selective exposure to Growth/Value investment styles. Performance for each investment is measured relative to the appropriate index benchmark for its category. Target asset-allocation percentages by major category are 45%-55% equity securities, 20%-30% fixed income, and up to 25% in a combination of other investments such as real estate, hedge funds, and private equity. Investment managers have full discretion as to investment decisions regarding funds under their management to the extent permitted within investment guidelines.

Although investment managers may, at their discretion and within investment guidelines, invest in Anadarko securities, there are no direct investments in Anadarko securities included in plan assets. There may be, however, indirect investments in Anadarko securities through the plans' collective fund investments. The expected long-term rate of return on plan assets assumption was determined using the year-end 2015 pension investment balances by asset class and expected long-term asset allocation. The expected return for each asset class reflects capital-market projections formulated using a forward-looking building-block approach while also taking into account historical return trends and current market conditions. Equity returns generally reflect long-term expectations of real earnings growth, dividend yield, and inflation. Returns on fixed-income securities are generally developed based on expected inflation, real bond yield, and risk spread (as appropriate), adjusted for the expected effect that changing yields have on the rate of return. Other asset-class returns are derived from their relationship to the equity and fixed-income markets.

**ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2015, 2014, AND 2013**

16. Pension Plans, Other Postretirement Benefits, and Defined-Contribution Plans (Continued)

The fair value of the Company's pension plan assets by asset class and input level within the fair-value hierarchy were as follows:

millions **December 31, 2015**	**Level 1**	**Level 2**	**Level 3**	**Total**
Investments				
Cash and cash equivalents	$ 5	$ 54	$ —	$ 59
Fixed income				
Mortgage-backed securities	—	36	—	36
U.S. government securities	—	53	—	53
Other fixed-income securities [1]	46	236	—	282
Equity securities				
Domestic	330	80	—	410
International	130	289	—	419
Other				
Real estate	—	57	104	161
Private equity	—	—	92	92
Hedge funds and other alternative strategies	7	—	127	134
Other	—	30	—	30
Total investments [2]	$ 518	$ 835	$ 323	$ 1,676
Liabilities				
Hedge funds and other alternative strategies	$ (3)	$ —	$ —	$ (3)
Total liabilities	$ (3)	$ —	$ —	$ (3)
December 31, 2014				
Investments				
Cash and cash equivalents	$ 3	$ 53	$ —	$ 56
Fixed income				
Mortgage-backed securities	—	51	—	51
U.S. government securities	—	56	—	56
Other fixed-income securities [1]	48	212	—	260
Equity securities				
Domestic	446	130	—	576
International	124	299	—	423
Other				
Real estate	—	56	94	150
Private equity	—	—	84	84
Hedge funds and other alternative strategies	9	—	126	135
Other	—	30	—	30
Total investments [2]	$ 630	$ 887	$ 304	$ 1,821
Liabilities				
Hedge funds and other alternative strategies	$ (3)	$ —	$ —	$ (3)
Total liabilities	$ (3)	$ —	$ —	$ (3)

(1) Amounts include investments in diversified fixed-income collective investment funds with exposure to mortgage-backed securities, government-issued securities, corporate debt, and other fixed-income securities.
(2) Amount excludes receivables and payables, primarily related to Level 1 investments.

**ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2015, 2014, AND 2013**

16. Pension Plans, Other Postretirement Benefits, and Defined-Contribution Plans (Continued)

Investments in securities traded in active markets are measured based on unadjusted quoted prices, which represent Level 1 inputs. Investments based on Level 2 inputs include direct investments in corporate debt and other fixed-income securities as well as shares of open-end mutual funds or similar investment vehicles that do not have a readily determinable fair value but are valued at the net asset value per share (NAV). For such funds, the NAV is the value at which investors transact with the fund, and is determined by the fund based on the estimated fair values of the underlying fund assets. Fair value of investments included as Level 3 inputs generally also reflect investments valued at fund NAVs, but, unlike investments characteristic of Level 2 fair-value measurements, such plan assets have significant liquidity restrictions or other features that are not reflected in NAV.

The following summarizes changes in the fair value of investments based on Level 3 inputs:

millions	Hedge Funds and Other Alternative Strategies	Private Equity	Real Estate	Total
Balance at January 1, 2014	$ 79	$ 72	$ 86	$ 237
Acquisitions (dispositions), net	42	—	2	44
Actual return on plan assets				
Relating to assets sold during the reporting period	2	5	—	7
Relating to assets still held at the reporting date	3	7	6	16
Balance at December 31, 2014	$ 126	$ 84	$ 94	$ 304
Acquisitions (dispositions), net	**1**	**(4)**	**2**	**(1)**
Actual return on plan assets				
Relating to assets sold during the reporting period	**—**	**11**	**—**	**11**
Relating to assets still held at the reporting date	**—**	**1**	**8**	**9**
Balance at December 31, 2015	**$ 127**	**$ 92**	**$ 104**	**$ 323**

Risks and Uncertainties The plan assets include various investment securities that are exposed to various risks such as interest-rate, credit, and market risks. Due to the level of risk associated with certain investment securities, it is possible that changes in the values of investment securities could significantly impact the plan assets.

The plan assets may include securities with contractual cash flows such as asset-backed securities, collateralized mortgage obligations, and commercial mortgage-backed securities, including securities backed by subprime mortgage loans. The value, liquidity, and related income of those securities are sensitive to changes in economic conditions, including real estate values, delinquencies or defaults, or both, and may be adversely affected by shifts in the market's perception of the issuers and changes in interest rates.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2015, 2014, AND 2013

16. Pension Plans, Other Postretirement Benefits, and Defined-Contribution Plans (Continued)

Cash Contributions and Expected Benefit Payments While reported benefit obligations exceed the fair value of pension and other postretirement plan assets at December 31, 2015, the Company monitors the status of its funded pension plans to ensure that plan funds are sufficient to continue paying benefits. Contributions to funded plans increase plan assets while contributions to unfunded plans are used to fund current benefit payments.

The following summarizes the Company's contributions for 2015 and expected contributions for 2016:

millions	Expected 2016	2015
Funded pension plans	$ 5	$ 4
Unfunded pension plans	25	39
Unfunded other postretirement plans	16	15
Total	$ 46	$ 58

The following summarizes estimated benefit payments for the next ten years, including benefit increases due to continuing employee service:

millions	Pension Benefit Payments	Other Benefit Payments
2016	$ 171	$ 16
2017	197	17
2018	194	17
2019	214	17
2020	209	18
2021-2025	1,199	92

Defined-Contribution Plans The Company maintains several defined-contribution benefit plans, the most significant of which is the Anadarko Employee Savings Plan (ESP). All regular employees of the Company on its U.S. payroll are eligible to participate in the ESP by making elective contributions that are matched by the Company, subject to certain limitations. The Company recognized expense of $76 million for both 2015 and 2014, and $78 million for 2013, related to these plans.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2015, 2014, AND 2013

17. Stockholders' Equity

Common Stock The following summarizes the changes in the Company's outstanding shares of common stock:

millions	**2015**	2014	2013
Shares of common stock issued			
Shares at January 1	**526**	523	519
Exercise of stock options	**1**	2	2
Issuance of restricted stock	**1**	1	2
Shares at December 31	**528**	526	523
Shares of common stock held in treasury			
Shares at January 1	**19**	19	18
Shares received for restricted stock vested and options exercised	**1**	—	1
Shares at December 31	**20**	19	19
Shares of common stock outstanding at December 31	**508**	507	504

The Company's basic earnings per share (EPS) is computed based on the average number of shares of common stock outstanding for the period and includes the effect of any participating securities and TEUs as appropriate. Diluted EPS includes the effect of the Company's outstanding stock options, restricted stock awards, restricted stock units, and TEUs, if the inclusion of these items is dilutive.

The following provides a reconciliation between basic and diluted EPS attributable to common stockholders for the years ended December 31:

millions except per-share amounts	**2015**	2014	2013
Net income (loss)			
Net income (loss) attributable to common stockholders	**$ (6,692)**	$ (1,750)	$ 801
Less distributions on participating securities	**3**	4	2
Less undistributed income allocated to participating securities	**—**	—	4
Basic	**$ (6,695)**	$ (1,754)	$ 795
Diluted	**$ (6,695)**	$ (1,754)	$ 795
Shares			
Average number of common shares outstanding—basic	**508**	506	502
Dilutive effect of stock options	**—**	—	3
Average number of common shares outstanding—diluted	**508**	506	505
Excluded due to anti-dilutive effect	**11**	11	4
Net income (loss) per common share			
Basic	**$ (13.18)**	$ (3.47)	$ 1.58
Diluted	**$ (13.18)**	$ (3.47)	$ 1.58

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2015, 2014, AND 2013

18. Accumulated Other Comprehensive Income (Loss)

The following summarizes the after-tax changes in the balances of accumulated other comprehensive income (loss):

millions	Interest-rate Derivatives Previously Subject to Hedge Accounting	Pension and Other Postretirement Plans	Total
Balance at December 31, 2012	$ (61)	$ (579)	$ (640)
Other comprehensive income (loss), before reclassifications	—	264	264
Reclassifications to Consolidated Statement of Income	7	84	91
Net other comprehensive income (loss)	7	348	355
Balance at December 31, 2013	$ (54)	$ (231)	$ (285)
Other comprehensive income (loss), before reclassifications	—	(256)	(256)
Reclassifications to Consolidated Statement of Income	6	18	24
Net other comprehensive income (loss)	6	(238)	(232)
Balance at December 31, 2014	$ (48)	$ (469)	$ (517)
Other comprehensive income (loss), before reclassifications	**—**	**87**	**87**
Reclassifications to Consolidated Statement of Income	**6**	**41**	**47**
Net other comprehensive income (loss)	**6**	**128**	**134**
Balance at December 31, 2015	**$ (42)**	**$ (341)**	**$ (383)**

19. Share-Based Compensation

At December 31, 2015, 16 million shares of the 31 million shares of Anadarko common stock originally authorized for awards under active share-based compensation plans remained available for future issuance. The Company generally issues new shares to satisfy awards under employee share-based payment plans. The number of shares available is reduced by awards granted. The following summarizes share-based compensation expense for the years ended December 31:

millions	**2015**	2014	2013
Restricted stock	**$ 157**	$ 144	$ 122
Stock options	**19**	21	27
Other equity-classified awards	**1**	1	1
Value creation plan	**(4)**	136	—
Performance-based unit awards	**(1)**	23	4
Other liability-classified awards	**—**	—	1
Pretax compensation expense	**$ 172**	$ 325	$ 155
Income tax benefit	**$ 64**	$ 120	$ 57

Cash flows from financing activities included excess tax benefits related to share-based compensation of $6 million in 2015, $22 million in 2014, and $11 million in 2013. Cash received from stock option exercises was $28 million in 2015, $99 million in 2014, and $135 million in 2013.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2015, 2014, AND 2013

19. Share-Based Compensation (Continued)

Equity-Classified Awards

Restricted Stock Certain employees may be granted restricted stock in the form of restricted stock awards or restricted stock units. Restricted stock is subject to forfeiture restrictions and cannot be sold, transferred, or disposed of during the restriction period. The holders of restricted stock awards have the same rights as a stockholder of the Company with respect to such shares, including the right to vote and receive dividends or other distributions paid with respect to the shares. A restricted stock unit is equivalent to a restricted stock award except that unit holders do not have the right to vote. Restricted stock vests over service periods ranging from the date of grant generally up to three years and is not considered issued and outstanding until vested.

Non-employee directors are granted deferred shares, which are also considered restricted stock, that are held in a grantor trust by the Company until payable. Non-employee directors may receive these shares in a lump-sum payment or in annual installments.

The following summarizes the Company's restricted stock activity:

	Shares *(millions)*	**Weighted-Average Grant-Date Fair Value** *(per share)*
Non-vested at January 1, 2015	3.60	$ 85.31
Granted	2.35	$ 79.40
Vested	(1.76)	$ 84.18
Forfeited	(0.21)	$ 84.34
Non-vested at December 31, 2015	3.98	$ 82.39

The weighted-average grant-date fair value per share of restricted stock granted was $87.42 during 2014 and $84.17 during 2013. The total fair value of restricted shares vested was $141 million during 2015, $132 million during 2014, and $110 million during 2013, based on the market price at the vesting date. At December 31, 2015, total unrecognized compensation cost related to restricted stock of $213 million is expected to be recognized over a weighted-average remaining service period of 1.9 years.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2015, 2014, AND 2013

19. Share-Based Compensation (Continued)

Stock Options Certain employees may be granted nonqualified options to purchase shares of Anadarko common stock with an exercise price equal to, or greater than, the fair market value of Anadarko common stock on the date of grant. These stock options generally vest over three years from the date of grant and terminate at the earlier of the date of exercise or seven years from the date of grant.

The fair value of stock option awards is determined using the Black-Scholes option-pricing model with the following assumptions:

- *Expected life*—Based on historical exercise behavior.
- *Volatility*—Based on an average of historical volatility over the expected life of an option and the 12-month average implied volatility.
- *Risk-free interest rates*—Based on the U.S. Treasury rate over the expected life of an option.
- *Dividend yield*—Based on a 12-month average dividend yield, taking into account the Company's expected dividend policy over the expected life of an option.
- *Expected forfeiture*—Based on historical forfeiture experience.

The Company used the following weighted-average assumptions to estimate the fair value of stock options granted:

	2015	2014	2013
Weighted-average grant-date fair value	**$ 18.18**	$ 23.55	$ 26.27
Assumptions			
Expected option life—years	**4.9**	4.9	4.8
Volatility	**32.4%**	29.9%	33.9%
Risk-free interest rate	**1.4%**	1.6%	1.3%
Dividend yield	**1.4%**	1.1%	0.8%

The following summarizes the Company's stock option activity:

	Shares *(millions)*	**Weighted-Average Exercise Price** *(per share)*	**Weighted-Average Remaining Contractual Term** *(years)*	**Aggregate Intrinsic Value** *(millions)*
Outstanding at January 1, 2015	6.79	$ 69.96		
Granted	1.16	$ 69.37		
Exercised [(1)]	(0.66)	$ 42.37		
Forfeited or expired	(0.24)	$ 87.08		
Outstanding at December 31, 2015	7.05	$ 71.86	3.40	$ 13.9
Vested or expected to vest at December 31, 2015	6.98	$ 71.77	3.37	$ 13.9
Exercisable at December 31, 2015	5.07	$ 69.08	2.28	$ 13.9

(1) The total intrinsic value of stock options exercised was $23 million during 2015, $88 million during 2014, and $80 million during 2013, based on the difference between the market price at the exercise date and the exercise price.

At December 31, 2015, total unrecognized compensation cost related to stock options of $38 million is expected to be recognized over a weighted-average remaining service period of 2.2 years.

**ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2015, 2014, AND 2013**

19. Share-Based Compensation (Continued)

Liability-Classified Awards

Value Creation Plan As a part of its employee compensation program, the Company offered an incentive compensation program that provided non-officer employees the opportunity to earn cash bonus awards based on the Company's TSR for the year, compared to the TSR of a predetermined group of peer companies. The Company paid $134 million during 2015 related to the plan and zero during 2014 and 2013. The Value Creation Plan was discontinued as an active plan beginning in 2015.

Performance-Based Unit Awards Certain officers of the Company were provided Performance Unit Award Agreements with two- and three-year performance periods. The vesting of these units is based on comparing the Company's TSR to the TSR of a predetermined group of peer companies over the specified performance period. Each performance unit represents the value of one share of the Company's common stock. Following the end of each performance period, the value of the vested performance units, if any, is paid in cash. The Company paid $9 million related to vested performance units in 2015, $12 million in 2014, and $15 million in 2013. At December 31, 2015, the Company's liability under Performance Unit Award Agreements was $16 million, with total unrecognized compensation cost related to these awards of $27 million expected to be recognized over a weighted-average remaining performance period of 2.4 years.

20. Noncontrolling Interests

WGP, a publicly traded consolidated subsidiary, is a limited partnership that owns interests in WES. In 2015, Anadarko sold 2.3 million WGP common units to the public and raised net proceeds of $130 million and in 2014 sold approximately 6 million WGP common units to the public and raised net proceeds of $335 million. In June 2015, Anadarko issued 9.2 million TEUs, which include an equity component that may be settled in WGP common units. For additional disclosure of the TEU effect on noncontrolling interests, see Note 10—Tangible Equity Units. At December 31, 2015, Anadarko's ownership interest in WGP consisted of an 87.3% limited partner interest and the entire non-economic general partner interest. The remaining 12.7% limited partner interest in WGP was owned by the public.

WES, a publicly traded consolidated subsidiary, is a limited partnership that acquires, owns, develops, and operates midstream assets. WES issued approximately 874 thousand common units to the public and raised net proceeds of $57 million in 2015, issued approximately 10 million common units to the public and raised net proceeds of $691 million in 2014, and issued approximately 12 million common units to the public and raised net proceeds of $725 million in 2013. In addition, WES issued 11 million Class C units to Anadarko in 2014 to partially fund the DBM acquisition. These units will receive quarterly distributions in the form of additional Class C units until the end of 2017, unless WES elects to convert the units to common units earlier or Anadarko elects to extend the conversion date. During 2015, WES distributed 498 thousand Class C units to Anadarko. At December 31, 2015, WGP's ownership interest in WES consisted of a 34.6% limited partner interest, the entire 1.8% general partner interest, and all of the WES incentive distribution rights. At December 31, 2015, Anadarko also owned an 8.5% limited partner interest in WES through other subsidiaries' ownership of common and Class C units. The remaining 55.1% limited partner interest in WES was owned by the public.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2015, 2014, AND 2013

21. Supplemental Cash Flow Information

For the year ended December 31, 2015, the Company's Consolidated Statement of Cash Flows includes an \$881 million increase in tax receivable related to the Tronox settlement included in (increase) decrease in accounts receivable, offset by an \$881 million uncertain tax position included in other items, net. The following summarizes cash paid (received) for interest and income taxes, as well as non-cash investing and financing activities, for the years ended December 31:

millions	**2015**	2014	2013
Cash paid (received)			
Interest, net of amounts capitalized[1]	**\$ 2,019**	\$ 689	\$ 627
Income taxes, net of refunds	**26**	956	169
Non-cash investing activities			
Fair value of properties and equipment from non-cash transactions	**\$ 178**	\$ 18	\$ 62
Asset retirement cost additions	**273**	348	297
Accruals of property, plant, and equipment	**754**	1,177	1,446
Net liabilities assumed (divested) in acquisitions and divestitures	**(114)**	(92)	(80)
Property insurance receivable	**49**	—	—
Non-cash investing and financing activities			
Capital lease obligation	**\$ —**	\$ 13	\$ 8
Floating production, storage, and offloading vessel construction period obligation	**59**	128	17

[1] Includes \$1.2 billion of interest related to the Tronox settlement payment in 2015.

22. Segment Information

Anadarko's business segments are separately managed due to distinct operational differences and unique technology, distribution, and marketing requirements. The Company's three reporting segments are oil and gas exploration and production, midstream, and marketing. The oil and gas exploration and production segment explores for and produces oil, condensate, natural gas, and NGLs, and plans for the development and operation of the Company's LNG project in Mozambique. The midstream segment engages in gathering, processing, treating, and transporting Anadarko and third-party oil, natural-gas, and NGLs production. The midstream reporting segment consists of two operating segments, WES and other midstream, which are aggregated into one reporting segment due to similar financial and operating characteristics. The marketing segment sells much of Anadarko's oil, natural-gas, and NGLs production, as well as third-party purchased volumes.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2015, 2014, AND 2013

22. Segment Information (Continued)

To assess the performance of Anadarko's operating segments, the chief operating decision maker analyzes Adjusted EBITDAX. The Company defines Adjusted EBITDAX as income (loss) before income taxes; gains (losses) on divestitures, net; exploration expense; DD&A; impairments; interest expense; total (gains) losses on derivatives, net, less net cash from settlement of commodity derivatives; and certain items not related to the Company's normal operations, less net income (loss) attributable to noncontrolling interests. During the periods presented, items not related to the Company's normal operations included other operating expenses such as Deepwater Horizon settlement and related costs and the Algeria exceptional profits tax settlement, Tronox-related contingent loss, and certain other nonoperating items included in other (income) expense, net. The Company's definition of Adjusted EBITDAX excludes gains (losses) on divestitures, net and exploration expense as they are not indicators of operating efficiency for a given reporting period. However, exploration expense is monitored by management as part of costs incurred in exploration and development activities. Similarly, DD&A and impairments are excluded from Adjusted EBITDAX as a measure of segment operating performance because capital expenditures are evaluated at the time capital costs are incurred. Adjusted EBITDAX also excludes interest expense to allow for assessment of segment operating results without regard to Anadarko's financing methods or capital structure. Total (gains) losses on derivatives, net, less net cash from settlement of commodity derivatives are excluded from Adjusted EBITDAX because these (gains) losses are not considered a measure of asset operating performance. Finally, net income (loss) attributable to noncontrolling interests is excluded from the Company's measure of Adjusted EBITDAX because it represents earnings that are not attributable to the Company's common stockholders.

Management believes that the presentation of Adjusted EBITDAX provides information useful in assessing the Company's financial condition and results of operations and that Adjusted EBITDAX is a widely accepted financial indicator of a company's ability to incur and service debt, fund capital expenditures, and make distributions to stockholders. Adjusted EBITDAX as defined by Anadarko may not be comparable to similarly titled measures used by other companies and should be considered in conjunction with net income (loss) attributable to common stockholders and other performance measures such as operating income or cash flows from operating activities. Below is a reconciliation of consolidated Adjusted EBITDAX to income (loss) before income taxes for the years ended December 31:

millions	**2015**	2014	2013
Income (loss) before income taxes	**$ (9,689)**	$ 54	$ 2,106
(Gains) losses on divestitures, net	**1,022**	(1,891)	470
Exploration expense	**2,644**	1,639	1,329
DD&A	**4,603**	4,550	3,927
Impairments	**5,075**	836	794
Interest expense	**825**	772	686
Total (gains) losses on derivatives, net, less net cash from settlement of commodity derivatives	**235**	578	(307)
Other operating expense	**74**	97	48
Tronox-related contingent loss	**5**	4,360	850
Certain other nonoperating items	**22**	22	110
Less net income (loss) attributable to noncontrolling interests	**(120)**	187	140
Consolidated Adjusted EBITDAX	**$ 4,936**	$ 10,830	$ 9,873

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2015, 2014, AND 2013

22. Segment Information (Continued)

The Company's accounting policies for individual segments are the same as those described in the summary of significant accounting policies, with the following exception: certain intersegment commodity contracts may meet the GAAP definition of a derivative instrument, which would be accounted for at fair value under GAAP. However, Anadarko does not recognize any mark-to-market adjustments on such intersegment arrangements. Additionally, intersegment asset transfers are accounted for at historical cost basis, and do not give rise to gain or loss recognition.

Information presented below as "Other and Intersegment Eliminations" includes corporate costs, results from hard-minerals royalties, and net cash from settlement of commodity derivatives. The following summarizes selected financial information for Anadarko's reporting segments:

millions	Oil and Gas Exploration & Production	Midstream	Marketing	Other and Intersegment Eliminations	Total
2015					
Sales revenues	$ 4,734	$ 727	$ 4,025	$ —	$ 9,486
Intersegment revenues	3,178	1,207	(3,476)	(909)	—
Other	—	—	—	234	234
Total revenues and other [(1)]	7,912	1,934	549	(675)	9,720
Operating costs and expenses [(2)]	3,456	998	743	(86)	5,111
Net cash from settlement of commodity derivatives	—	—	—	(335)	(335)
Other (income) expense, net [(3)]	—	—	—	127	127
Net income (loss) attributable to noncontrolling interests	—	(120)	—	—	(120)
Total expenses and other	3,456	878	743	(294)	4,783
Total (gains) losses on derivatives, net included in marketing revenue, less net cash from settlement	—	—	(1)	—	(1)
Adjusted EBITDAX	$ 4,456	$ 1,056	$ (195)	$ (381)	$ 4,936
Net properties and equipment	$ 25,742	$ 5,876	$ —	$ 2,133	$ 33,751
Capital expenditures	$ 5,029	$ 770	$ —	$ 89	$ 5,888
Goodwill	$ 4,945	$ 450	$ —	$ —	$ 5,395

(1) Total revenues and other excludes gains (losses) on divestitures, net since these gains and losses are excluded from Adjusted EBITDAX.

(2) Operating costs and expenses excludes exploration expense, DD&A, impairments, and other operating expense since these expenses are excluded from Adjusted EBITDAX.

(3) Other (income) expense, net excludes certain other nonoperating items since these items are excluded from Adjusted EBITDAX.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2015, 2014, AND 2013

22. Segment Information (Continued)

millions	Oil and Gas Exploration & Production	Midstream	Marketing	Other and Intersegment Eliminations	Total
2014					
Sales revenues	$ 8,603	$ 484	$ 7,288	$ —	$ 16,375
Intersegment revenues	6,225	1,338	(6,771)	(792)	—
Other	—	—	—	204	204
Total revenues and other (1)	14,828	1,822	517	(588)	16,579
Operating costs and expenses (2)	4,216	972	740	17	5,945
Net cash from settlement of commodity derivatives	—	—	—	(377)	(377)
Other (income) expense, net (3)	—	—	—	(2)	(2)
Net income (loss) attributable to noncontrolling interests	—	187	—	—	187
Total expenses and other	4,216	1,159	740	(362)	5,753
Total (gains) losses on derivatives, net included in marketing revenue, less net cash from settlement	—	—	4	—	4
Adjusted EBITDAX	$ 10,612	$ 663	$ (219)	$ (226)	$ 10,830
Net properties and equipment	$ 32,717	$ 6,697	$ —	$ 2,175	$ 41,589
Capital expenditures	$ 7,934	$ 1,149	$ —	$ 173	$ 9,256
Goodwill	$ 5,123	$ 453	$ —	$ —	$ 5,576
2013					
Sales revenues	$ 7,090	$ 387	$ 7,390	$ —	$ 14,867
Intersegment revenues	6,405	1,105	(6,859)	(651)	—
Other	—	—	—	184	184
Total revenues and other (1)	13,495	1,492	531	(467)	15,051
Operating costs and expenses (2)	3,635	843	652	20	5,150
Net cash from settlement of commodity derivatives	—	—	—	(95)	(95)
Other (income) expense, net (3)	—	—	—	(21)	(21)
Net income (loss) attributable to noncontrolling interests	—	140	—	—	140
Total expenses and other	3,635	983	652	(96)	5,174
Total (gains) losses on derivatives, net included in marketing revenue, less net cash from settlement	—	—	(4)	—	(4)
Adjusted EBITDAX	$ 9,860	$ 509	$ (125)	$ (371)	$ 9,873
Net properties and equipment	$ 33,409	$ 5,408	$ 9	$ 2,103	$ 40,929
Capital expenditures	$ 7,008	$ 1,248	$ —	$ 267	$ 8,523
Goodwill	$ 5,317	$ 175	$ —	$ —	$ 5,492

(1) Total revenues and other excludes gains (losses) on divestitures, net since these gains and losses are excluded from Adjusted EBITDAX.

(2) Operating costs and expenses excludes exploration expense, DD&A, impairments, and other operating expense since these expenses are excluded from Adjusted EBITDAX.

(3) Other (income) expense, net excludes certain other nonoperating items since these items are excluded from Adjusted EBITDAX.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2015, 2014, AND 2013

22. Segment Information (Continued)

The following represents Anadarko's sales revenues (based on the origin of the sales) and net properties and equipment by geographic area:

	Years Ended December 31,		
millions	**2015**	2014	2013
Sales Revenues			
United States	**$ 7,819**	$ 13,083	$ 11,290
Algeria	**1,189**	2,435	2,184
Other International	**478**	857	1,393
Total sales revenues	**$ 9,486**	$ 16,375	$ 14,867

	December 31,	
millions	**2015**	2014
Net Properties and Equipment		
United States	**$ 29,625**	$ 37,186
Algeria	**1,271**	1,431
Other International	**2,855**	2,972
Total net properties and equipment	**$ 33,751**	$ 41,589

Major Customers In 2015 and 2014, there were no sales to customers that exceeded 10% of the Company's total sales revenues. Sales to Total S.A. were $2.0 billion in 2013. These amounts are included in the oil and gas exploration and production reporting segment.

ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES
(Unaudited)

The unaudited supplemental information on oil and gas exploration and production activities for 2015, 2014, and 2013 has been presented in accordance with Financial Accounting Standards Board Accounting Standards Codification Topic 932, *Extractive Activities—Oil and Gas* and the Securities and Exchange Commission's final rule, *Modernization of Oil and Gas Reporting*. Disclosures by geographic area include the United States and International. For 2015, the International geographic area consisted of proved reserves located in Algeria and Ghana. The Company sold its Chinese subsidiary during 2014.

Oil and Gas Reserves

The following reserves disclosures reflect estimates of proved reserves, proved developed reserves, and proved undeveloped reserves, net of third-party royalty interests, of oil, condensate, natural gas, and natural-gas liquids (NGLs) owned at each year end and changes in proved reserves during each of the last three years. Oil, condensate, and NGLs volumes are presented in millions of barrels (MMBbls) and natural-gas volumes are presented in billions of cubic feet (Bcf) at a pressure base of 14.73 pounds per square inch. Total volumes are presented in millions of barrels of oil equivalent (MMBOE). For this computation, one barrel is the equivalent of 6,000 cubic feet of natural gas. Shrinkage associated with NGLs has been deducted from the natural-gas reserves volumes.

Reserves for international locations are calculated in accordance with the terms of governing agreements. The international reserves include estimated quantities allocated to Anadarko for recovery of costs and income taxes and Anadarko's net equity share after recovery of such costs.

The Company's estimates of proved reserves are made using available geological and reservoir data as well as production performance data. These estimates are reviewed annually by internal reservoir engineers and revised, either upward or downward, as warranted by additional data. The results of infill drilling are treated as positive revisions due to increases to expected recovery. Other revisions are due to changes in, among other things, development plans, reservoir performance, commodity prices, economic conditions, and governmental restrictions.

The prices below were used to compute the information presented in the following tables and are adjusted only for fixed and determinable amounts under provisions in existing contracts:

	Oil and Condensate per Bbl	Natural Gas per MMBtu	NGLs per Bbl [1]
December 31, 2015	$ 50.28	$ 2.59	$ 19.47
December 31, 2014	$ 94.99	$ 4.35	$ 45.25
December 31, 2013	$ 96.78	$ 3.67	N/A

[1] The benchmark price for NGLs was previously the same as that for oil, but was converted to a NGLs-specific price beginning in 2014.

MMBtu—million British thermal units
Bbl—barrel

ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES
(Unaudited)

Oil and Gas Reserves (Continued)

	Oil and Condensate (MMBbls)			Natural Gas (Bcf)		
	United States	International	Total	United States	International	Total
Proved Reserves						
December 31, 2012	511	256	767	8,329	—	8,329
Revisions of prior estimates	96	21	117	1,276	—	1,276
Extensions, discoveries, and other additions	52	14	66	416	—	416
Purchases in place	1	—	1	153	—	153
Sales in place	(10)	—	(10)	(4)	—	(4)
Production	(58)	(32)	(90)	(965)	—	(965)
December 31, 2013	592	259	851	9,205	—	9,205
Revisions of prior estimates	167	18	185	710	31	741
Extensions, discoveries, and other additions	25	—	25	196	—	196
Purchases in place	—	—	—	—	—	—
Sales in place	(6)	(17)	(23)	(492)	—	(492)
Production	(74)	(35)	(109)	(951)	—	(951)
December 31, 2014	**704**	**225**	**929**	**8,668**	**31**	**8,699**
Revisions of prior estimates	**2**	**(6)**	**(4)**	**(888)**	**4**	**(884)**
Extensions, discoveries, and other additions	**15**	**—**	**15**	**60**	**—**	**60**
Purchases in place	**—**	**—**	**—**	**8**	**—**	**8**
Sales in place	**(111)**	**—**	**(111)**	**(1,003)**	**—**	**(1,003)**
Production	**(85)**	**(31)**	**(116)**	**(854)**	**(5)**	**(859)**
December 31, 2015	**525**	**188**	**713**	**5,991**	**30**	**6,021**
Proved Developed Reserves						
December 31, 2012	318	208	526	6,445	—	6,445
December 31, 2013	347	202	549	7,120	—	7,120
December 31, 2014	352	190	542	6,635	27	6,662
December 31, 2015	**332**	**159**	**491**	**5,184**	**30**	**5,214**
Proved Undeveloped Reserves						
December 31, 2012	193	48	241	1,884	—	1,884
December 31, 2013	245	57	302	2,085	—	2,085
December 31, 2014	352	35	387	2,033	4	2,037
December 31, 2015	**193**	**29**	**222**	**807**	**—**	**807**

ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES
(Unaudited)

Oil and Gas Reserves (Continued)

	NGLs (MMBbls)			Total (MMBOE)		
	United States	**International**	**Total**	**United States**	**International**	**Total**
Proved Reserves						
December 31, 2012	393	12	405	2,292	268	2,560
Revisions of prior estimates [1]	17	—	17	326	21	347
Extensions, discoveries, and other additions	10	—	10	131	14	145
Purchases in place	9	—	9	36	—	36
Sales in place	(1)	—	(1)	(12)	—	(12)
Production	(33)	—	(33)	(252)	(32)	(284)
December 31, 2013	395	12	407	2,521	271	2,792
Revisions of prior estimates [1]	129	2	131	414	25	439
Extensions, discoveries, and other additions	5	—	5	63	—	63
Purchases in place	—	—	—	—	—	—
Sales in place	(19)	—	(19)	(107)	(17)	(124)
Production	(44)	(1)	(45)	(276)	(36)	(312)
December 31, 2014	**466**	**13**	**479**	**2,615**	**243**	**2,858**
Revisions of prior estimates [1]	**(99)**	**4**	**(95)**	**(245)**	**(1)**	**(246)**
Extensions, discoveries, and other additions	**4**	**—**	**4**	**29**	**—**	**29**
Purchases in place	**—**	**—**	**—**	**1**	**—**	**1**
Sales in place	**(1)**	**—**	**(1)**	**(279)**	**—**	**(279)**
Production	**(45)**	**(2)**	**(47)**	**(272)**	**(34)**	**(306)**
December 31, 2015	**325**	**15**	**340**	**1,849**	**208**	**2,057**
Proved Developed Reserves						
December 31, 2012	283	—	283	1,675	208	1,883
December 31, 2013	268	—	268	1,801	202	2,003
December 31, 2014	304	13	317	1,762	207	1,969
December 31, 2015	**257**	**15**	**272**	**1,453**	**179**	**1,632**
Proved Undeveloped Reserves						
December 31, 2012	110	12	122	617	60	677
December 31, 2013	127	12	139	720	69	789
December 31, 2014	162	—	162	853	36	889
December 31, 2015	**68**	**—**	**68**	**396**	**29**	**425**

[1] Revisions of prior estimates include the effects of new infill drilling, changes in commodity prices, and other updates, including changes in economic conditions, changes in reservoir performance, and changes to development plans. Additions generated by Anadarko's infill drilling programs were 89 MMBOE for 2015, 577 MMBOE for 2014, and 410 MMBOE for 2013.

ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES
(Unaudited)

Total proved reserves decreased by 801 MMBOE in 2015 primarily due to the following:

- *Revisions of prior estimates* Prior estimates of proved reserves were revised downward by 246 MMBOE. Negative revisions of 624 MMBOE were due to the decline in commodity prices and include a reduction to NGLs reserves of 43 MMBOE associated with price-induced ethane rejection. The negative price-related revisions were partially offset by a net increase of 378 MMBOE driven by increases from improved economics associated with performance improvements coupled with reduced year-end costs, increases from successful infill drilling mainly in the Wattenberg area of the Rocky Mountains Region (Rockies), and decreases primarily associated with updates to development plans to align with the current economic environment.
- *Extensions and discoveries* Proved reserves increased by 29 MMBOE through the extension of proved acreage, primarily as a result of successful drilling in the Wolfcamp shale play in the Southern and Appalachia Region. Although shale plays represented only 20% of the Company's total proved reserves at December 31, 2015, growth in the shale plays contributed almost all of the total extensions and discoveries.
- *Sales in place* Proved developed reserves decreased by 238 MMBOE primarily associated with the divestiture of a portion of the Company's East Texas assets in the Southern and Appalachia Region and enhanced oil recovery and coalbed methane assets in the Rockies. Proved undeveloped reserves decreased by 41 MMBOE primarily associated with divestiture activities in the Rockies.

Total proved reserves increased by 66 MMBOE in 2014 primarily due to the following:

- *Revisions of prior estimates* Proved reserves increased by 577 MMBOE related to successful infill drilling in large onshore areas such as the Wattenberg area and the Eagleford and Haynesville shales. Partially offsetting these positive infill revisions was a net decrease of 138 MMBOE, primarily associated with the optimization of horizontal drilling locations and the discontinuation of vertical well workover plans in the Wattenberg area.
- *Extensions and discoveries* Proved reserves increased by 63 MMBOE primarily as a result of successful drilling in the Marcellus and Wolfcamp shale plays. Although shale plays represented only 17% of the Company's total proved reserves at December 31, 2014, growth in the shale plays contributed 49 MMBOE, or 78%, of the total extensions and discoveries.
- *Sales in place* Proved developed reserves decreased by 69 MMBOE and proved undeveloped reserves decreased by 55 MMBOE due to divestitures, including the divestiture of the Company's interest in the Pinedale/Jonah assets in Wyoming, the Company's Chinese subsidiary, and a portion of the Company's working interest in the East Texas Chalk area.

Total proved reserves increased by 232 MMBOE in 2013 primarily due to the following:

- *Revisions of prior estimates* Proved reserves increased by 410 MMBOE related to successful infill drilling, primarily in large onshore areas such as Wattenberg, Greater Natural Buttes, and the Eagleford shale, and 30 MMBOE resulting from improved oil and natural-gas prices. Partially offsetting these positive revisions were decreases of 53 MMBbls of NGLs reserves due to lower ethane prices and 40 MMBOE due to other non-price-related revisions primarily in the Rockies.
- *Extensions and discoveries* Proved reserves increased by 145 MMBOE as the result of successful drilling primarily in the Marcellus shale and the Gulf of Mexico. Although shale plays represented only 13% of the Company's total proved reserves at December 31, 2013, growth in the shale plays contributed 70 MMBOE, or 48%, of the total extensions and discoveries.
- *Purchases in place* Proved reserves increased by 36 MMBOE due to acquisitions related to domestic assets almost exclusively in the Rockies.
- *Sales in place* Proved undeveloped reserves decreased by 12 MMBOE primarily due to a partial sale of a working interest in the Gulf of Mexico Heidelberg development project.

ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES
(Unaudited)

Capitalized Costs

Capitalized costs include the cost of properties, equipment, and facilities for oil and natural-gas producing activities. Capitalized costs for proved properties include costs for oil and natural-gas leaseholds where proved reserves have been identified, development wells, and related equipment and facilities, including development wells in progress. Capitalized costs for unproved properties include costs for acquiring oil and gas leaseholds where no proved reserves have been identified, including costs of exploratory wells that are in the process of drilling or in active completion, and costs of exploratory wells suspended or waiting on completion. Capitalized costs associated with activities of the Company's midstream and marketing reporting segments, liquefied natural gas (LNG) facilities costs, and other corporate activities are not included.

millions	United States	International	Total
December 31, 2015			
Capitalized			
Unproved properties	**$ 2,742**	**$ 739**	**$ 3,481**
Proved properties	**50,275**	**5,472**	**55,747**
	53,017	**6,211**	**59,228**
Less accumulated DD&A	**31,366**	**2,281**	**33,647**
Net capitalized costs	**$ 21,651**	**$ 3,930**	**$ 25,581**
December 31, 2014			
Capitalized			
Unproved properties	$ 3,858	$ 1,291	$ 5,149
Proved properties	53,545	4,895	58,440
	57,403	6,186	63,589
Less accumulated DD&A	29,055	1,902	30,957
Net capitalized costs	$ 28,348	$ 4,284	$ 32,632

ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES
(Unaudited)

Costs Incurred in Oil and Gas Property Acquisition, Exploration, and Development

Amounts reported as costs incurred include both capitalized costs and costs charged to expense when incurred for oil and gas property acquisition, exploration, and development activities. Costs incurred also include new asset retirement obligations established in the current year as well as increases or decreases to the asset retirement obligations resulting from changes to cost estimates during the year. Exploration costs presented below include the costs of drilling and equipping successful and unsuccessful exploration wells during the year, geological and geophysical expenses, and the costs of retaining undeveloped leaseholds. Development costs include the costs of drilling and equipping development wells, and construction of related production facilities. Costs associated with activities of the Company's midstream and marketing reporting segments, LNG facilities costs, and other corporate activities are not included.

millions	United States	International	Total
Year Ended December 31, 2015			
Property acquisitions			
Unproved	**$ 293**	**$ 1**	**$ 294**
Proved	**81**	**—**	**81**
Exploration	**503**	**609**	**1,112**
Development	**3,660**	**606**	**4,266**
Total costs incurred	**$ 4,537**	**$ 1,216**	**$ 5,753**
Year Ended December 31, 2014			
Property acquisitions			
Unproved	$ 264	$ 19	$ 283
Proved	3	—	3
Exploration	1,095	616	1,711
Development	6,158	557	6,715
Total costs incurred	$ 7,520	$ 1,192	$ 8,712
Year Ended December 31, 2013			
Property acquisitions			
Unproved	$ 282	$ 45	$ 327
Proved	324	—	324
Exploration	1,031	939	1,970
Development	4,421	444	4,865
Total costs incurred	$ 6,058	$ 1,428	$ 7,486

ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES
(Unaudited)

Results of Operations

Results of operations for producing activities consist of all activities within the oil and gas exploration and production reporting segment. Net revenues from production include only the revenues from the production and sale of oil, condensate, natural gas, and NGLs. Gains (losses) on property dispositions represent net gains or losses on sales of oil and gas properties. Production costs are costs to operate and maintain the Company's wells, related equipment, and supporting facilities used in oil and gas operations, including the cost of labor, well service and repair, location maintenance, power and fuel, gathering, processing, transportation, other taxes, and production-related general and administrative costs. Exploration expenses include dry hole costs, leasehold impairments, geological and geophysical expenses, and the costs of retaining unproved leaseholds. Other operating expense includes Deepwater Horizon settlement and related costs and the Algeria exceptional profits tax settlement, representing the Company's resolution of the Algeria exceptional profits tax dispute with Sonatrach, which provided for the transfer of $1.7 billion of oil to the Company over a 12-month period ending in mid-2013. Income tax expense is calculated by applying the current statutory tax rates to the revenues after deducting costs, which include depreciation, depletion, and amortization allowances, after giving effect to permanent differences. The results of operations exclude general office overhead and interest expense attributable to oil and gas activities.

millions	United States	International	Total
Year Ended December 31, 2015			
Net revenues from production			
Third-party sales	$ 4,409	$ 673	$ 5,082
Sales to consolidated affiliates	2,184	994	3,178
Gains (losses) on property dispositions	(976)	(14)	(990)
	5,617	1,653	7,270
Production costs			
Oil and gas operating	815	199	1,014
Oil and gas transportation	1,083	34	1,117
Production-related general and administrative expenses	398	11	409
Other taxes	218	270	488
	2,514	514	3,028
Exploration expenses	1,447	1,197	2,644
Depreciation, depletion, and amortization	3,785	399	4,184
Impairments related to oil and gas properties	4,033	—	4,033
Other operating expense	150	—	150
	(6,312)	(457)	(6,769)
Income tax expense	(2,332)	252	(2,080)
Results of operations	$ (3,980)	$ (709)	$ (4,689)

ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES
(Unaudited)

Results of Operations (Continued)

millions	United States	International	Total
Year Ended December 31, 2014			
Net revenues from production			
Third-party sales	$ 7,425	$ 1,518	$ 8,943
Sales to consolidated affiliates	4,453	1,773	6,226
Gains (losses) on property dispositions	(91)	1,982	1,891
	11,787	5,273	17,060
Production costs			
Oil and gas operating	968	203	1,171
Oil and gas transportation	1,084	33	1,117
Production-related general and administrative expenses	394	32	426
Other taxes	652	535	1,187
	3,098	803	3,901
Exploration expenses	1,218	421	1,639
Depreciation, depletion, and amortization	3,783	398	4,181
Impairments related to oil and gas properties	821	—	821
Other operating expense	163	—	163
	2,704	3,651	6,355
Income tax expense	995	979	1,974
Results of operations	$ 1,709	$ 2,672	$ 4,381
Year Ended December 31, 2013			
Net revenues from production			
Third-party sales	$ 6,567	$ 856	$ 7,423
Sales to consolidated affiliates	3,685	2,720	6,405
Gains (losses) on property dispositions	(618)	(3)	(621)
	9,634	3,573	13,207
Production costs			
Oil and gas operating	874	218	1,092
Oil and gas transportation	959	22	981
Production-related general and administrative expenses	332	5	337
Other taxes	569	455	1,024
	2,734	700	3,434
Exploration expenses	611	718	1,329
Depreciation, depletion and amortization	3,222	399	3,621
Impairments related to oil and gas properties	704	—	704
Other operating expense	54	33	87
	2,309	1,723	4,032
Income tax expense	845	1,005	1,850
Results of operations	$ 1,464	$ 718	$ 2,182

ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES
(Unaudited)

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

Estimates of future net cash flows from proved reserves are computed based on the average beginning-of-the-month prices during the 12-month period for the year. Estimated future net cash flows for all periods presented are reduced by estimated future development, production, and abandonment and dismantlement costs based on existing costs, assuming continuation of existing economic conditions, and by estimated future income tax expense. These estimates also include assumptions about the timing of future production of proved reserves, and timing of future development, production costs, and abandonment and dismantlement. Income tax expense, both U.S. and foreign, is calculated by applying the existing statutory tax rates, including any known future changes, to the pretax net cash flows, giving effect to any permanent differences and reduced by the applicable tax basis. The effect of tax credits is considered in determining the income tax expense. The 10% discount factor is prescribed by U.S. Generally Accepted Accounting Principles.

The present value of future net cash flows is not an estimate of the fair value of Anadarko's proved reserves. An estimate of fair value would also take into account, among other things, anticipated changes in future prices and costs, the expected recovery of reserves in excess of proved reserves, and a discount factor more representative of the time value of money and the risks inherent in producing oil and natural gas. Significant changes in estimated reserves volumes or commodity prices could have a material effect on the Company's Consolidated Financial Statements.

millions	United States	International	Total
December 31, 2015			
Future cash inflows	**$ 42,919**	**$ 10,392**	**$ 53,311**
Future production costs	**21,100**	**3,829**	**24,929**
Future development costs	**7,209**	**637**	**7,846**
Future income tax expenses	**4,146**	**2,423**	**6,569**
Future net cash flows	**10,464**	**3,503**	**13,967**
10% annual discount for estimated timing of cash flows	**3,372**	**910**	**4,282**
Standardized measure of discounted future net cash flows	**$ 7,092**	**$ 2,593**	**$ 9,685**
December 31, 2014			
Future cash inflows	$ 114,384	$ 23,795	$ 138,179
Future production costs	36,390	6,061	42,451
Future development costs	14,794	1,356	16,150
Future income tax expenses	21,813	6,968	28,781
Future net cash flows	41,387	9,410	50,797
10% annual discount for estimated timing of cash flows	17,239	2,898	20,137
Standardized measure of discounted future net cash flows	$ 24,148	$ 6,512	$ 30,660
December 31, 2013			
Future cash inflows	$ 102,765	$ 28,454	$ 131,219
Future production costs	33,271	6,819	40,090
Future development costs	12,285	1,501	13,786
Future income tax expenses	20,222	8,148	28,370
Future net cash flows	36,987	11,986	48,973
10% annual discount for estimated timing of cash flows	15,818	4,049	19,867
Standardized measure of discounted future net cash flows	$ 21,169	$ 7,937	$ 29,106

ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES
(Unaudited)

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

millions	United States	International	Total
2015			
Balance at January 1	**$ 24,148**	**$ 6,512**	**$ 30,660**
Sales and transfers of oil and gas produced, net of production costs	**(4,079)**	**(1,153)**	**(5,232)**
Net changes in prices and production costs	**(28,967)**	**(8,010)**	**(36,977)**
Changes in estimated future development costs	**4,408**	**221**	**4,629**
Extensions, discoveries, additions, and improved recovery, less related costs	**219**	**—**	**219**
Development costs incurred during the period	**2,311**	**379**	**2,690**
Revisions of previous quantity estimates	**(1,890)**	**47**	**(1,843)**
Purchases of minerals in place	**30**	**—**	**30**
Sales of minerals in place	**(2,262)**	**—**	**(2,262)**
Accretion of discount	**3,648**	**1,143**	**4,791**
Net change in income taxes	**9,940**	**3,193**	**13,133**
Other	**(414)**	**261**	**(153)**
Balance at December 31	**$ 7,092**	**$ 2,593**	**$ 9,685**
2014			
Balance at January 1	$ 21,169	$ 7,937	$ 29,106
Sales and transfers of oil and gas produced, net of production costs	(8,780)	(2,492)	(11,272)
Net changes in prices and production costs	(3,981)	(1,984)	(5,965)
Changes in estimated future development costs	(4,180)	(250)	(4,430)
Extensions, discoveries, additions, and improved recovery, less related costs	963	—	963
Development costs incurred during the period	2,591	279	2,870
Revisions of previous quantity estimates	13,703	1,921	15,624
Purchases of minerals in place	—	—	—
Sales of minerals in place	(591)	(696)	(1,287)
Accretion of discount	3,221	1,341	4,562
Net change in income taxes	(1,294)	549	(745)
Other	1,327	(93)	1,234
Balance at December 31	$ 24,148	$ 6,512	$ 30,660

ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES
(Unaudited)

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves (Continued)

millions	United States	International	Total
2013			
Balance at January 1	$ 17,538	$ 8,776	$ 26,314
Sales and transfers of oil and gas produced, net of production costs	(7,517)	(2,881)	(10,398)
Net changes in prices and production costs	1,433	(1,072)	361
Changes in estimated future development costs	(2,326)	(193)	(2,519)
Extensions, discoveries, additions, and improved recovery, less related costs	2,659	(128)	2,531
Development costs incurred during the period	1,076	193	1,269
Revisions of previous quantity estimates	6,526	1,324	7,850
Purchases of minerals in place	253	—	253
Sales of minerals in place	284	—	284
Accretion of discount	2,671	1,465	4,136
Net change in income taxes	(1,865)	401	(1,464)
Other	437	52	489
Balance at December 31	$ 21,169	$ 7,937	$ 29,106

ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL QUARTERLY INFORMATION
(Unaudited)

Quarterly Financial Data

The following summarizes quarterly financial data for 2015 and 2014:

millions except per-share amounts	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2015				
Sales revenues	**$ 2,585**	**$ 2,637**	**$ 2,230**	**$ 2,034**
Gains (losses) on divestitures and other, net	**(264)**	**(1)**	**(542)**	**19**
Impairments	**2,783**	**30**	**758**	**1,504**
Operating income (loss)	**(4,208)**	**90**	**(2,549)**	**(2,142)**
Net income (loss)	**(3,236)**	**108**	**(2,160)**	**(1,524)**
Net income (loss) attributable to noncontrolling interests	**32**	**47**	**75**	**(274)**
Net income (loss) attributable to common stockholders	**(3,268)**	**61**	**(2,235)**	**(1,250)**
Earnings per share				
Net income (loss) attributable to common stockholders—basic	**$ (6.45)**	**$ 0.12**	**$ (4.41)**	**$ (2.45)**
Net income (loss) attributable to common stockholders—diluted	**$ (6.45)**	**$ 0.12**	**$ (4.41)**	**$ (2.45)**
Average number common shares outstanding—basic	**507**	**508**	**508**	**508**
Average number common shares outstanding—diluted	**507**	**509**	**508**	**508**
2014				
Sales revenues	$ 4,338	$ 4,385	$ 4,230	$ 3,422
Gains (losses) on divestitures and other, net	1,506	54	780	(245)
Impairments	3	117	394	322
Operating income (loss)	2,975	1,209	1,698	(479)
Tronox-related contingent loss	4,300	19	19	22
Net income (loss)	(2,626)	266	1,147	(350)
Net income (loss) attributable to noncontrolling interests	43	39	60	45
Net income (loss) attributable to common stockholders	(2,669)	227	1,087	(395)
Earnings per share				
Net income (loss) attributable to common stockholders—basic	$ (5.30)	$ 0.45	$ 2.13	$ (0.78)
Net income (loss) attributable to common stockholders—diluted	$ (5.30)	$ 0.45	$ 2.12	$ (0.78)
Average number common shares outstanding—basic	504	505	506	507
Average number common shares outstanding—diluted	504	507	508	507

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

EVALUATION AND DISCLOSURE CONTROLS AND PROCEDURES

Anadarko's Chief Executive Officer and Chief Financial Officer performed an evaluation of the Company's disclosure controls and procedures as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended. The Company's disclosure controls and procedures are designed to ensure that information required to be disclosed by the Company in reports it files or submits under the Securities Exchange Act of 1934, as amended, is recorded, processed, summarized, and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission, and to ensure that the information required to be disclosed by the Company in reports that it files or submits under the Securities Exchange Act of 1934, as amended, is accumulated and communicated to the Company's management, including the principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure. Based on this evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that the Company's disclosure controls and procedures are effective as of December 31, 2015.

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

See *Management's Assessment of Internal Control Over Financial Reporting* under Item 8 of this Form 10-K.

ATTESTATION REPORT OF THE REGISTERED PUBLIC ACCOUNTING FIRM

See *Report of Independent Registered Public Accounting Firm* under Item 8 of this Form 10-K.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There were no changes in Anadarko's internal control over financial reporting during the fourth quarter of 2015 that materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting. See *Management's Assessment of Internal Control Over Financial Reporting* under Item 8 of this Form 10-K.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers, and Corporate Governance

See *Anadarko Board of Directors, Corporate Governance—Committees of the Board, Corporate Governance—Board of Directors,* and *Section 16(a) Beneficial Ownership Reporting Compliance* in the Definitive Proxy Statement (Proxy Statement) for the Annual Meeting of Stockholders of Anadarko Petroleum Corporation to be held May 10, 2016 (to be filed with the Securities and Exchange Commission prior to March 31, 2016), each of which is incorporated herein by reference.

See list of *Executive Officers of the Registrant* under Items 1 and 2 of this Form 10-K, which is incorporated herein by reference.

The Company's Code of Business Conduct and Ethics and the Code of Ethics for the Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer (Code of Ethics) can be found on the Company's website located at www.anadarko.com/Responsibility/Good-Governance. Any stockholder may request a printed copy of the Code of Ethics by submitting a written request to the Company's Corporate Secretary. If the Company amends the Code of Ethics or grants a waiver, including an implicit waiver, from the Code of Ethics, the Company will disclose the information on its website. The waiver information will remain on the website for at least 12 months after the initial disclosure of such waiver.

Item 11. Executive Compensation

See *Corporate Governance—Board of Directors—Compensation and Benefits Committee Interlocks and Insider Participation, Corporate Governance—Board of Directors—Director Compensation, Corporate Governance—Director Compensation Table for 2015, Compensation and Benefits Committee Report on 2015 Executive Compensation, Compensation Discussion and Analysis,* and *Executive Compensation* in the Proxy Statement, each of which is incorporated herein by reference. The Compensation and Benefits Committee Report and related information incorporated by reference herein shall not be deemed "soliciting material" or to be "filed" with the Securities and Exchange Commission, nor shall such information be incorporated by reference into any future filing under the Securities Act of 1933 or Securities Exchange Act of 1934, each as amended, except to the extent that the Company specifically incorporates it by reference into such filing.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

See *Security Ownership of Certain Beneficial Owners and Management* in the Proxy Statement and *Securities Authorized for Issuance under Equity Compensation Plans* under Item 5 of this Form 10-K, each of which is incorporated herein by reference.

Item 13. Certain Relationships and Related Transactions, and Director Independence

See *Corporate Governance—Board of Directors* and *Transactions with Related Persons* in the Proxy Statement, each of which is incorporated herein by reference.

Item 14. Principal Accounting Fees and Services

See *Independent Auditor* in the Proxy Statement, which is incorporated herein by reference.

PART IV

Item 15. Exhibits, Financial Statement Schedules

a) EXHIBITS

The following documents are filed as part of this Form 10-K or incorporated by reference:

(1) The Consolidated Financial Statements of Anadarko Petroleum Corporation are listed on the Index to this Form 10-K, page 82.

(2) Exhibits not incorporated by reference to a prior filing are designated by an asterisk (*) and are filed herewith or double asterisk (**) and are furnished herewith; all exhibits not so designated are incorporated herein by reference to a prior filing under File Number 1-8968 as indicated.

Exhibit Number	Description
2 (i)	Agreement and Plan of Merger dated as of June 22, 2006, among Anadarko Petroleum Corporation, APC Acquisition Sub, Inc. and Kerr-McGee Corporation, filed as Exhibit 2.2 to Form 8-K filed on June 26, 2006
3 (i)	Restated Certificate of Incorporation of Anadarko Petroleum Corporation, dated May 21, 2009, filed as Exhibit 3.3 to Form 8-K filed on May 22, 2009
(ii)	By-Laws of Anadarko Petroleum Corporation, amended and restated as of September 15, 2015, filed as Exhibit 3.1 to Form 8-K filed on September 21, 2015
4 (i)	Trustee Indenture, dated as of September 19, 2006, Anadarko Petroleum Corporation to The Bank of New York Trust Company, N.A., filed as Exhibit 4.1 to Form 8-K filed on September 19, 2006
(ii)	Third Supplemental Indenture, dated as of June 10, 2015, between Anadarko Petroleum Corporation and The Bank of New York Mellon Trust Company, N.A., filed as Exhibit 4.2 to Form 8-K filed on June 10, 2015
(iii)	Second Supplemental Indenture dated October 4, 2006, among Anadarko Petroleum Corporation, Kerr-McGee Corporation, and Citibank, N.A., filed as Exhibit 4.1 to Form 8-K filed on October 6, 2006
(iv)	Ninth Supplemental Indenture dated October 4, 2006, among Anadarko Petroleum Corporation, Kerr-McGee Corporation, and Citibank, N.A., filed as Exhibit 4.2 to Form 8-K filed on October 6, 2006
(v)	Officers' Certificate of Anadarko Petroleum Corporation, dated March 2, 2009, establishing the 7.625% Senior Notes due 2014 and the 8.700% Senior Notes due 2019, filed as Exhibit 4.1 to Form 8-K filed on March 6, 2009
(vi)	Form of 7.625% Senior Notes due 2014, filed as Exhibit 4.2 to Form 8-K filed on March 6, 2009
(vii)	Form of 8.700% Senior Notes due 2019, filed as Exhibit 4.3 to Form 8-K filed on March 6, 2009
(viii)	Officers' Certificate of Anadarko Petroleum Corporation, dated June 9, 2009, establishing the 5.75% Senior Notes due 2014, the 6.95% Senior Notes due 2019 and the 7.95% Senior Notes due 2039, filed as Exhibit 4.1 to Form 8-K filed on June 12, 2009
(ix)	Form of 5.75% Senior Notes due 2014, filed as Exhibit 4.2 to Form 8-K filed on June 12, 2009
(x)	Form of 6.95% Senior Notes due 2019, filed as Exhibit 4.3 to Form 8-K filed on June 12, 2009
(xi)	Form of 7.95% Senior Notes due 2039, filed as Exhibit 4.4 to Form 8-K filed on June 12, 2009
(xii)	Officers' Certificate of Anadarko Petroleum Corporation dated March 9, 2010, establishing the 6.200% Senior Notes due 2040, filed as Exhibit 4.1 to Form 8-K filed on March 16, 2010

	Exhibit Number		Description
	4	(xiii)	Form of 6.200% Senior Notes due 2040, filed as Exhibit 4.2 to Form 8-K filed on March 16, 2010
		(xiv)	Officers' Certificate of Anadarko Petroleum Corporation dated August 9, 2010, establishing the 6.375% Senior Notes due 2017, filed as Exhibit 4.1 to Form 8-K filed on August 12, 2010
		(xv)	Form of 6.375% Senior Notes due 2017, filed as Exhibit 4.2 to Form 8-K filed on August 12, 2010
		(xvi)	Officers' Certificate of Anadarko Petroleum Corporation dated July 7, 2014, establishing the 3.45% Senior Notes due 2024 and the 4.50% Senior Notes due 2044, filed as Exhibit 4.1 to Form 8-K filed on July 7, 2014
		(xvii)	Form of 3.45% Senior Notes due 2024, filed as Exhibit 4.2 to Form 8-K filed on July 7, 2014
		(xviii)	Form of 4.50% Senior Notes due 2044, filed as Exhibit 4.3 to Form 8-K filed on July 7, 2014
		(xix)	Purchase Contract Agreement, dated June 10, 2015, between Anadarko Petroleum Corporation and The Bank of New York Mellon Trust Company, N.A., filed as Exhibit 4.1 to Form 8-K filed on June 10, 2015
		(xx)	Form of Unit (included in Exhibit 4.xix)
		(xxi)	Form of Purchase Contract (included in Exhibit 4.xix)
		(xxii)	Form of Amortizing Note (included in Exhibit 4.ii)
†	10	(i)	1998 Director Stock Plan of Anadarko Petroleum Corporation, effective January 30, 1998, filed as Appendix A to DEF 14A filed on March 16, 1998
†		(ii)	Form of Anadarko Petroleum Corporation 1998 Director Stock Plan Stock Option Agreement, filed as Exhibit 10.1 to Form 8-K filed on November 17, 2005
†		(iii)	Anadarko Petroleum Corporation Amended and Restated 1999 Stock Incentive Plan, filed as Appendix A to DEF 14A filed on March 18, 2005
†		(iv)	Form of Anadarko Petroleum Corporation Executive 1999 Stock Incentive Plan Stock Option Agreement, filed as Exhibit 10.2 to Form 8-K filed on November 17, 2005
†		(v)	Form of Anadarko Petroleum Corporation Non-Executive 1999 Stock Incentive Plan Stock Option Agreement, filed as Exhibit 10.3 to Form 8-K filed on November 17, 2005
†		(vi)	Form of Stock Option Agreement—1999 Stock Incentive Plan (UK Nationals), filed as Exhibit 10.4 to Form 8-K filed on November 17, 2005
†		(vii)	Amendment to Stock Option Agreement Under the Anadarko Petroleum Corporation 1999 Stock Incentive Plan, filed as Exhibit 10.1 to Form 8-K filed on January 23, 2007
†		(viii)	Anadarko Petroleum Corporation 1999 Stock Incentive Plan (Amendment to Performance Unit Agreement), filed as Exhibit 10.3 to Form 8-K filed on November 13, 2007
†		(ix)	Form of Anadarko Petroleum Corporation 1999 Stock Incentive Plan Restricted Stock Agreement, filed as Exhibit 10(b)(xxiv) to Form 10-K for year ended December 31, 1999, filed on March 16, 2000
†		(x)	Form of Anadarko Petroleum Corporation 1999 Stock Incentive Plan Restricted Stock Unit Award Letter, filed as Exhibit 10.1 to Form 8-K filed on November 13, 2007
†		(xi)	The Approved UK Sub-Plan of the Anadarko Petroleum Corporation 1999 Stock Incentive Plan, filed as Exhibit 10(b)(xxiv) to Form 10-K for year ended December 31, 2003, filed on March 4, 2004
†		(xii)	Key Employee Change of Control Contract, filed as Exhibit 10(b)(xxii) to Form 10-K for year ended December 31, 1997, filed on March 18, 1998
†		(xiii)	First Amendment to Anadarko Petroleum Corporation Key Employee Change of Control Contract, filed as Exhibit 10(b) to Form 10-Q for quarter ended September 30, 2000, filed on November 13, 2000

	Exhibit Number	Description
†	10 (xiv)	Form of Amendment to Anadarko Petroleum Corporation Key Employee Change of Control Contract, filed as Exhibit 10(b)(ii) to Form 10-Q for quarter ended June 30, 2003, filed on August 11, 2003
†	(xv)	Form of Key Employee Change of Control Contract (2011), filed as Exhibit 10(i) to Form 10-Q for quarter ended June 30, 2011, filed on July 27, 2011
†	(xvi)	Form of Amendment to Anadarko Petroleum Corporation Key Employee Change of Control Contract (Applicable to Vice Presidents Other Than Executive Officers as of October 2013), filed as Exhibit 10(ii) to Form 10-Q for the quarter ended March 31, 2015, filed on May 4, 2015
†	(xvii)	Letter Agreement regarding Post-Retirement Benefits, dated February 16, 2004—Robert J. Allison, Jr., filed as Exhibit 10(b)(xxxiv) to Form 10-K for year ended December 31, 2003, filed on March 4, 2004
†	(xviii)	Anadarko Petroleum Corporation Savings Restoration Plan (As Amended and Restated Effective January 1, 2007), filed as Exhibit 10(xxii) to Form 10-K for year ended December 31, 2009, filed on February 23, 2010
†	(xix)	First Amendment, dated July 1, 2010, to the Anadarko Petroleum Corporation Savings Restoration Plan (As Amended and Restated Effective January 1, 2007), filed as Exhibit 10 (xviii) to Form 10-K for the year ended December 31, 2014, filed on February 20, 2015
†	(xx)	Second Amendment, dated November 30, 2011, to the Anadarko Petroleum Corporation Savings Restoration Plan (As Amended and Restated Effective January 1, 2007), filed as Exhibit 10(xix) to Form 10-K for the year ended December 31, 2014, filed on February 20, 2015
†	(xxi)	Third Amendment, dated December 18, 2014, to the Anadarko Petroleum Corporation Savings Restoration Plan (As Amended and Restated Effective January 1, 2007), filed as Exhibit 10 (xx) to Form 10-K for the year ended December 31, 2014, filed on February 20, 2015
†	(xxii)	Anadarko Retirement Restoration Plan (As Amended and Restated Effective as of November 7, 2007), filed as Exhibit 10.2 to Form 8-K filed on November 13, 2007
†	(xxiii)	First Amendment, dated November 30, 2011, to the Anadarko Retirement Restoration Plan (As Amended and Restated Effective January 1, 2007), filed as Exhibit 10(xxii) to Form 10-K for the year ended December 31, 2014, filed on February 20, 2015
†	(xxiv)	Anadarko Petroleum Corporation Estate Enhancement Program, filed as Exhibit 10(b)(xxxiv) to Form 10-K for year ended December 31, 1998, filed on March 15, 1999
†	(xxv)	Estate Enhancement Program Agreement between Anadarko Petroleum Corporation and Eligible Executives, filed as Exhibit 10(b)(xxxv) to Form 10-K for year ended December 31, 1998, filed on March 15, 1999
†	(xxvi)	Estate Enhancement Program Agreements effective November 29, 2000, filed as Exhibit 10(b)(xxxxii) to Form 10-K for year ended December 31, 2000, filed on March 15, 2001
†	(xxvii)	Anadarko Petroleum Corporation Management Life Insurance Plan, restated November 1, 2002, filed as Exhibit 10(b)(xxxii) to Form 10-K for year ended December 31, 2002, filed on March 14, 2003
†	(xxviii)	First Amendment to Anadarko Petroleum Corporation Management Life Insurance Plan, effective June 30, 2003, filed as Exhibit 10(b)(xliii) to Form 10-K for year ended December 31, 2003, filed on March 4, 2004
†	(xxix)	Second Amendment to Anadarko Petroleum Corporation Management Life Insurance Plan, effective January 1, 2008, filed as Exhibit 10(xxix) to Form 10-K for year ended December 31, 2009, filed on February 23, 2010
†	(xxx)	Anadarko Petroleum Corporation Officer Severance Plan, filed as Exhibit 10(b)(iv) to Form 10-Q for quarter ended September 30, 2003, filed on November 12, 2003
†	(xxxi)	Form of Termination Agreement and Release of All Claims Under Officer Severance Plan, filed as Exhibit 10(b)(v) to Form 10-Q for quarter ended September 30, 2003, filed on November 12, 2003

	Exhibit Number	Description
†	10 (xxxii)	Form of Director and Officer Indemnification Agreement, filed as Exhibit 10 to Form 8-K filed on September 3, 2004
	(xxxiii)	$5,000,000,000 Revolving Credit Agreement, dated as of September 2, 2010, among Anadarko Petroleum Corporation, as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A., DnB NorBank ASA, The Royal Bank of Scotland plc, Société Générale, and Wells Fargo Bank, N.A., as Syndication Agents, and the several lenders named therein, filed as Exhibit 10.1 to Form 8-K filed on September 8, 2010
	(xxxiv)	First Amendment to Revolving Credit Agreement, dated as of August 3, 2011, to the Revolving Credit Agreement dated as of September 2, 2010, among Anadarko Petroleum Corporation, as Borrower, JPMorgan Chase Bank, N.A. as Administrative Agent, Bank of America, N.A., DnB Nor Bank ASA, The Royal Bank of Scotland plc, Société Générale, and Wells Fargo Bank, N.A., as co-syndication agents, and each of the Lenders from time to time party thereto, filed as Exhibit 10(i) to Form 10-Q for quarter ended September 30, 2011, filed on October 31, 2011
	(xxxv)	Second Amendment to Revolving Credit Agreement, dated as of March 26, 2014, to the Revolving Credit Agreement dated as of September 2, 2010, as amended on August 3, 2011, among Anadarko Petroleum Corporation, as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, Bank of America, N.A., DnB Nor Bank ASA, The Royal Bank of Scotland plc, Société Générale, and Wells Fargo Bank, N.A., as co-syndication agents, and each of the Lenders from time to time party thereto, filed as Exhibit 10(ii) to Form 10-Q for quarter ended March 31, 2014, filed on May 5, 2014
†	(xxxvi)	Anadarko Petroleum Corporation 2008 Omnibus Incentive Compensation Plan, effective as of May 20, 2008, filed as Exhibit 10.1 to Form 8-K filed on May 27, 2008
†	(xxxvii)	Form of Anadarko Petroleum Corporation 2008 Omnibus Incentive Compensation Plan Stock Option Award Agreement, filed as Exhibit 10.3 to Form 8-K filed on November 13, 2009
†	(xxxviii)	Form of Anadarko Petroleum Corporation 2008 Omnibus Incentive Compensation Plan Restricted Stock Unit Award Agreement, filed as Exhibit 10.1 to Form 8-K filed on November 13, 2009
†	(xxxvix)	Form of Anadarko Petroleum Corporation 2008 Omnibus Incentive Compensation Plan Performance Unit Award Agreement, filed as Exhibit 10.2 to Form 8-K filed on November 13, 2009
†	(xl)	Anadarko Petroleum Corporation 2008 Director Compensation Plan, effective as of May 20, 2008, filed as Exhibit 10.2 to Form 8-K filed on May 27, 2008
†*	(xli)	First Amendment to Anadarko Petroleum Corporation 2008 Director Compensation Plan, dated February 8, 2016
†	(xlii)	Form of Award Letter for Anadarko Petroleum Corporation 2008 Director Compensation Plan, filed as Exhibit 10.3 to Form 8-K filed on May 27, 2008
†	(xliii)	Form of Award Letter for Anadarko Petroleum Corporation 2008 Director Compensation Plan (2013), filed as Exhibit 10(i) to Form 10-Q for quarter ended June 30, 2013, filed on July 29, 2013
†*	(xliv)	Terms and Conditions of Elective Deferred Share Awards for Anadarko Petroleum Corporation 2008 Director Compensation Plan
†	(xlv)	Anadarko Petroleum Corporation Benefits Trust Agreement, amended and restated effective as of November 5, 2008, filed as Exhibit 10(lvi) to Form 10-K for year ended December 31, 2008, filed on February 25, 2009
†	(xlvi)	Anadarko Petroleum Corporation Deferred Compensation Plan (as amended and restated effective as of January 1, 2012), filed as Exhibit 10(i) to Form 10-Q for the quarter ended June 30, 2014, filed on July 29, 2014
†	(xlvii)	First Amendment, dated December 17, 2013, to the Anadarko Petroleum Corporation Deferred Compensation Plan (as amended and restated effective as of January 1, 2012), filed as Exhibit 10(ii) to Form 10-Q for the quarter ended June 30, 2014, filed on July 29, 2014

	Exhibit Number	Description
	10 (xlviii)	Operating Agreement, dated October 1, 2009, between BP Exploration & Production Inc., as Operator, and MOEX Offshore 2007 LLC, as Non-Operator, as ratified by that certain Ratification and Joinder of Operating Agreement, dated December 17, 2009, by and among BP Exploration & Production Inc., Anadarko Petroleum Corporation (as Non-Operator), Anadarko E&P Company LP (as predecessor in interest to Anadarko Petroleum Corporation), and MOEX Offshore 2007 LLC, together with material exhibits, filed as Exhibit 10 to Form 10-Q for quarter ended June 30, 2010, filed on August 3, 2010
	(xlix)	Confidential Settlement Agreement, Mutual Releases and Agreement to Indemnify, dated October 16, 2011, by and among BP Exploration & Production Inc., Anadarko Petroleum Corporation, Anadarko E&P Company LP, BP Corporation North America Inc. and BP p.l.c., filed as Exhibit 10(xlii) to Form 10-K for year ended December 31, 2011, filed on February 21, 2012 (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment)
†	(l)	Severance Agreement between R. A. Walker and Anadarko Petroleum Corporation, dated February 16, 2012, filed as Exhibit 10.2 to Form 8-K filed on February 21, 2012
†	(li)	Time Sharing Agreement between R. A. Walker and Anadarko Petroleum Corporation, dated May 15, 2012, filed as Exhibit 10(ii) to Form 10-Q for quarter ended June 30, 2012, filed on August 8, 2012
†	(lii)	First Amendment to Time Sharing Agreement between R.A. Walker and Anadarko Petroleum Corporation, dated June 2, 2015, filed as Exhibit 10(ii) to Form 10-Q for the quarter ended June 30, 2015, filed on July 28, 2015
†	(liii)	Anadarko Petroleum Corporation 2012 Omnibus Incentive Compensation Plan, effective as of May 15, 2012, filed as Exhibit 10.1 to Form 8-K filed on May 15, 2012
†	(liv)	Form of Anadarko Petroleum Corporation 2012 Omnibus Incentive Compensation Plan Stock Option Award Agreement, filed as Exhibit 10.2 to Form 8-K filed on May 15, 2012
†	(lv)	Form of Anadarko Petroleum Corporation 2012 Omnibus Incentive Compensation Plan Restricted Stock Unit Award Agreement, filed as Exhibit 10.3 to Form 8-K filed on May 15, 2012
†	(lvi)	Form of Anadarko Petroleum Corporation 2012 Omnibus Incentive Compensation Plan Performance Unit Award Agreement, filed as Exhibit 10.4 to Form 8-K filed on May 15, 2012
†	(lvii)	Form of Anadarko Petroleum Corporation 2012 Omnibus Incentive Compensation Plan Restricted Stock Unit Award Agreement, filed as Exhibit 10.1 to Form 8-K filed on November 9, 2012
†	(lviii)	Form of Anadarko Petroleum Corporation 2012 Omnibus Incentive Compensation Plan Performance Unit Award Agreement, filed as Exhibit 10.2 to Form 8-K filed on November 9, 2012
†	(lix)	Form of Anadarko Petroleum Corporation 2012 Omnibus Incentive Compensation Plan Performance Unit Award Agreement (2014), filed as Exhibit 10.1 to Form 8-K filed on November 10, 2014
†	(lx)	Form of U.K. Award Letter for Anadarko Petroleum Corporation 2008 Director Compensation Plan, filed as Exhibit 10.5 to Form 8-K filed on May 15, 2012
†	(lxi)	Amended and Restated Performance Unit Award Agreement, effective November 5, 2012, for R. A. Walker, filed as Exhibit 10.3 to Form 8-K filed on November 9, 2012
	(lxii)	Settlement Agreement dated as of April 3, 2014, by and among (1) the Anadarko Litigation Trust, (2) the United States of America in its capacity as plaintiff-intervenor in the Tronox Adversary Proceeding and acting for and on behalf of certain U.S. government agencies and (3) Anadarko Petroleum Corporation, Kerr-McGee Corporation, and certain other subsidiaries, filed as exhibit 10.1 to Form 8-K filed on April 3, 2014

	Exhibit Number		Description
	10	(lxiii)	Credit Agreement, dated as of June 17, 2014, among Anadarko Petroleum Corporation, as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, Wells Fargo Bank, National Association, as Syndication Agent, Bank of America, N.A., Citibank, N.A., The Royal Bank of Scotland plc, and The Bank of Tokyo-Mitsubishi UFJ, Ltd., as Co-Documentation Agents, and the additional lenders party thereto, filed as Exhibit 10.1 to Form 8-K filed on June 23, 2014
		(lxiv)	First Amendment to Credit Agreement, dated November 14, 2014, among Anadarko Petroleum Corporation, JPMorgan Chase Bank, N.A., as Administrative Agent, and the lenders party thereto, filed as Exhibit 10.1 to Form 8-K filed on November 19, 2014
		(lxv)	Amendment and Maturity Extension Agreement, dated December 14, 2015, among Anadarko Petroleum Corporation, JPMorgan Chase Bank, N.A., as Administrative Agent, and the lenders party thereto, filed as Exhibit 10.1 to Form 8-K filed on December 18, 2015
		(lxvi)	364-Day Revolving Credit Agreement, dated as of June 17, 2014, among Anadarko Petroleum Corporation, as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, Wells Fargo Bank, National Association, as Syndication Agent, Bank of America, N.A., Citibank, N.A., The Royal Bank of Scotland plc, and The Bank of Tokyo-Mitsubishi UFJ, Ltd., as Co-Documentation Agents, and the additional lenders party thereto, filed as Exhibit 10.2 to Form 8-K filed on June 23, 2014
		(lxvii)	First Amendment to 364-Day Revolving Credit Agreement, dated November 14, 2014, among Anadarko Petroleum Corporation, JPMorgan Chase Bank, N.A., as Administrative Agent, and the lenders party thereto, filed as Exhibit 10.2 to Form 8-K filed on November 19, 2014
		(lxviii)	Form of Commercial Paper Dealer Agreement for Commercial Paper Program, filed as Exhibit 10.1 to Form 8-K filed on January 21, 2015
†		(lxix)	Anadarko Petroleum Corporation Key Employee Change of Control Contract, dated June 1, 2015, for Christopher O. Champion, filed as Exhibit 10(i) to Form 10-Q for the quarter ended June 30, 2015, filed on July 28, 2015
		(lxx)	364-Day Revolving Credit Agreement, dated as of January 19, 2016, among Anadarko Petroleum Corporation, as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, Wells Fargo Bank, National Association, as Syndication Agent, Bank of America, N.A., The Bank of Tokyo-Mitsubishi UFJ, Ltd., Citibank, N.A., and Mizuho Bank, Ltd., as Co-Documentation Agents, and the additional lenders party thereto, filed as Exhibit 10.1 to Form 8-K filed on January 25, 2016
*	12		Computation of Ratios of Earnings to Fixed Charges
*	21		List of Subsidiaries
*	23	(i)	Consent of KPMG LLP
*	23	(ii)	Consent of Miller and Lents, Ltd.
*	24		Power of Attorney
*	31	(i)	Rule 13a-14(a)/15d-14(a) Certification—Chief Executive Officer
*	31	(ii)	Rule 13a-14(a)/15d-14(a) Certification—Chief Financial Officer
**	32		Section 1350 Certifications
*	99		Report of Miller and Lents, Ltd.
*	101	.INS	XBRL Instance Document
*	101	.SCH	XBRL Schema Document
*	101	.CAL	XBRL Calculation Linkbase Document
*	101	.DEF	XBRL Definition Linkbase Document
*	101	.LAB	XBRL Label Linkbase Document
*	101	.PRE	XBRL Presentation Linkbase Document

† Management contracts or compensatory plans or arrangements required to be filed pursuant to Item 15.

The total amount of securities of the registrant authorized under any instrument with respect to long-term debt not filed as an exhibit does not exceed 10% of the total assets of the registrants and its subsidiaries on a consolidated basis. The registrant agrees, upon request of the SEC, to furnish copies of any or all of such instruments to the SEC.

b) FINANCIAL STATEMENT SCHEDULES

Financial statement schedules have been omitted because they are not required, not applicable, or the information is included in the Company's Consolidated Financial Statements.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ANADARKO PETROLEUM CORPORATION

February 17, 2016 By: /s/ ROBERT G. GWIN

Robert G. Gwin
Executive Vice President, Finance and Chief Financial Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on February 17, 2016.

Name and Signature	Title
(i) Principal executive officer and director:	
/s/ R. A. WALKER R. A. Walker	Chairman, President and Chief Executive Officer
(ii) Principal financial officer:	
/s/ ROBERT G. GWIN Robert G. Gwin	Executive Vice President, Finance and Chief Financial Officer
(iii) Principal accounting officer:	
/s/ CHRISTOPHER O. CHAMPION Christopher O. Champion	Vice President, Chief Accounting Officer and Controller

(iv) Directors:*

ANTHONY R. CHASE
KEVIN P. CHILTON
H. PAULETT EBERHART
PETER J. FLUOR
RICHARD L. GEORGE
JOSEPH W. GORDER
JOHN R. GORDON
SEAN GOURLEY
MARK C. MCKINLEY
ERIC D. MULLINS

* Signed on behalf of each of these persons and on his own behalf:

By: /s/ ROBERT G. GWIN
Robert G. Gwin, Attorney-in-Fact

Exhibit 103

24-Feb-2016

Anadarko Petroleum Corp. (APC)

Credit Suisse Energy Summit

CORPORATE PARTICIPANTS

Robert P. Daniels
Executive VP-International & Deepwater Exploration

John M. Colglazier
Senior VP-Investor Relations & Communications

MANAGEMENT DISCUSSION SECTION

Unverified Participant

Great. Well, thanks, everyone, and thank you to Anadarko. Thank you, Bob, for presenting this morning. I mean, obviously, the area you cover, I mean, I would just observe that Anadarko has been a very good explorer, but also has been an absolutely superb executer of projects relative to the competition. So, congratulations.

But without further ado, I'd love to hear what you have to say. Thank you.

Robert P. Daniels
Executive VP-International & Deepwater Exploration

All right. Well thank you very much and thanks for the interest in Anadarko. I want to set this up first. Of course, we're going to have some forward-looking statements. If you're interested in the reconciliation to the non-GAAP numbers that may be in here, look to the website. And I do also want to point out that we have our investor conference call next Tuesday, 8:00 A.M. Central Time. And so you'll hear a lot more details on that call than I can give you today. I don't want to front run that. So with that, I hope we have a lot of you on that call.

When I look at how we entered 2015, we knew it was going to be a tough year. Commodity prices had come down, but service costs hadn't. And when we looked at our capital budget, we actually anticipated, in the capital budget, service cost reductions, but they weren't there yet. So we're actually kind of ahead of ourselves as to what we were actually planning on spending, almost committed to spending, relative to what our capital budget was. You can see how we did. We actually came in under the low end of it. We're very pleased with that.

On the cost control side, you can really look at about $500 million that we got out of controllable costs, out of the system last year. And again, that's just focusing on the base, everything that we needed to do to make sure that we met or exceeded all of our guidance numbers: lifting costs down on a per barrel basis, G&A down significantly.

The other thing, when we came out at the beginning of 2015, we thought we'd be reducing our capital by about 30%. We had to get costs down to even get within that range, and we thought that would lead to about flat production growth. And you can see what we were able to accomplish last year, about 11 million barrels, exceeding the guidance that we put out there, the mid-range of our guidance, and that's about 25,000 barrels a day of oil that contributed to that. So, the bulk of it was into the higher margin liquids; very pleased with that.

The reserve replacement, 130%. The F&D cost, $14, very competitive in a very challenging market. We're incredibly proud of what we accomplished last year. We think a lot of this is sustainable. We think that some of the

things that we put in place in the way of efficiencies, particularly around the drilling of wells, is something that will carry forward into whatever the next commodity price environment looks like. It's not just getting service cost reductions out of our vendors and suppliers. It's actual changing the way we're doing our business, changing the way we're drilling the wells, changing the way we're casing the wells, that will continue no matter what the commodity price cycle looks like.

We also closed $2 billion worth of monetizations, and that was to make sure that we were spending within our cash inflows. So, our capital budget was cash flows and monetizations that came together. We've done, I think John was saying, about $30 billion over the past 10 years, of monetizations. This is something we view as a core competency. We're constantly looking at our portfolio and managing that: where's our capital being invested, how things stack up in there, what's not getting funded, is that better off in somebody else's hands? And if so, we go out and monetize those.

So, I mentioned the well cost and improved efficiencies. An example of that will be at Wattenberg, where we cut 50% off our drilling costs just by changing our casing designs. This was a learning that we did in the Maverick, found a – or discovered kind of in the Maverick, and we took it up to see if it was applicable into Wattenberg, and it was. And it's amazing. The gain in efficiencies, cost reductions, that we got out of changing that casing design.

And then we still did exploration last year. We had a play opening discovery offshore Colombia in the deepwater. We think there's tremendous running room on that, and we'll be back drilling appraisal wells to it this year. But we have significant additional acreage up there that we think has been de-risked to a large extent, with the learnings from the two wells that we drilled last year.

So, all in all, extremely good 2015; very proud of what our people accomplished in a very challenging environment, and it set us up well coming into another challenging environment, which is 2016. Commodity price, as of course y'all know, continue to fall. We're at $30, sub $2 gas. That hits our cash flow, so we reduced our capital program. We came out on our earnings call and previewed that we would be about a 50% reduction in capital in 2016, relative to 2015. The importance of that is, we want to live within our cash inflows, and so capital has to match up to our cash flows from operations, any kind of monetizations that we have going on. And I'll talk more about that.

The bulk of this is coming out of our U.S. onshore activities. When we look at $30 oil in a short-cycle environment, we're just not getting the returns that we would want to get. And so, we're taking the activity levels down. It's something that we can turn back on fairly quickly, because it is a short cycle investment. But you really want to get a pricing environment that's going to give you the returns in the 18 months after your first production comes on. And we're not in that environment right now. So, that's one of the reasons that you'll see that that's down.

But, even with this reduced capital, we think that our production volumes maybe will fall 1% to 4%, but our oil volumes will stay flat year-over-year, fourth quarter to fourth quarter and overall which we think is a testament to the quality of our assets and the quality of our people that we're able to do that with 50% reduction in capital.

The other thing that goes into that, of course, so is the long-cycle investments that are paying dividends now. Our Lucius Field came online last year and hit nameplate capacity very quickly and is outperforming everything that we had hoped for.

Heidelberg came online January of this year in the Gulf of Mexico. That's early to what we had anticipated it would be when we first sanctioned the project, so that's good news for us. And then TEN in Ghana comes online

third quarter of this year. So, those are all oil assets. They're going to be adding to that; that help keep the oil volumes flat through the year.

We've mentioned on our earnings call that we have a billion dollars worth of – a billion-plus dollars worth of monetizations in the advanced stages. We'll talk more about that at the investor conference call next week. We recently reduced our dividend by 81%. That's going to free up about $450 million worth of cash to enhance our balance sheet.

And then we got ample liquidity. We got $900 million of cash on hand at the year-end 2015. We got $5 billion worth of undrawn credit facilities at the year-end. And with the other changes in operating – or changes in taxes and things like that, we feel like we've got a very good position on liquidity. And we can fund, through the cash flow from operations and our monetizations, the capital program as we go forward.

So, really the focus in 2016 is going to be on preserving and then enhancing the value. I want to make sure that we're doing things, the smart things: that we're preserving what we have and where we have the opportunities actually enhancing that. So, I mentioned the capital allocation. We are not letting opportunities go in the U.S. onshore. We're going to maintain the quality assets that we have, but we're going to minimize our activities until we get a better return on our investments.

We do have quite a few intentionally deferred uncompleted wells, IDUCs, out there from 2015. We can use those as kind of a lever if prices recover. If we need to bring some production volumes online, we have those available to us. And then the thing you're going to hear more about next week is these tieback opportunities in the Gulf of Mexico. You know our infrastructure in the Gulf of Mexico is extensive, and we're adding to that, of course, with the Lucius spar last year, Heidelberg spar coming on this year.

What that gives us access to is tiebacks of our own opportunities where we can go out, drill fault block nearby, tie the well back in or other peoples discoveries that may not have infrastructure to go to that we can bring into ours under a production handling agreement. So, we're going to focus on those. On everything that we've been doing in the Gulf of Mexico in the way of our own tiebacks will give us 30-plus% rate of return, even at the commodity prices that we're seeing today. And that's because we've already made the investment in the infrastructure. So, it's really enhancing the value of that infrastructure is what we're focusing on. We've got a lot of those opportunities. And so, we'll talk more about those.

And then, the portfolio management, this is something we always do. I mentioned what we've done over the past 10 years, the $2 billion last year already in advance stages on a billion dollars this year. We are always looking at can we upgrade our portfolio? What can we get rid of out of our portfolio? It's better off than somebody else's hands. So that's what we will continue through the year.

Very briefly, Wattenberg is one of our best assets, it's a world class asset. Thing I want to emphasize here is that net resources, 1.5 billion barrels, and the 4,000 identified locations. So this shows, we've got a depth of inventory out here that, in the right commodity cycle, we can get out there and accelerate very quickly. This is not the time to do it, but we're not going to lose anything. We're maintaining it. Doing everything we can to enhance it: focusing on the base, focusing on optimization, everything else that we can do without putting a lot of capital to work waiting for prices to recover, but phenomenal asset, lot of running room in it.

Next one, Delaware Basin, it's the same story a little earlier in its lifecycle. Again, billion barrels of resource potential, 5,000 identified Wolfcamp A locations and we're testing the other benches, Wolfcamp B, et cetera. You can see the EURs as we move across the field from the oilier portion on the east to the gassier portion on the west. Of course, you get higher EURs for lower value product as you move off to the east, but tremendous EURs out

APC-01753697

here. 600,000 gross acres that we control. We've de-risked the bulk of this in the A. We're still working on the B. We will be investing out here to maintain our acreage, to learn more as we go through. But again, it'll be very scaled down as we move through the year.

Gulf of Mexico, talked about the infrastructure. It's all shown on this map with our facilities. All the way from Independence Hub on the Eastern Gulf of Mexico, which finally went offline here just recently, to Boomvang in the West. The new ones, with Heidelberg and Lucius shown, Lucius the farthest south for existing infrastructure for Anadarko. And what that means is, we've got opportunities to maximize the value of that infrastructure and look at, where do we have tiebacks. And these are not things we're out there looking for right now. These have been on our books for quite some time.

We think this is a very, very good time to go out and bring some of these in, as we've come off plateau at some of these, and we have excess capacity on some of the facilities. So, very good returns on this, even at these commodity prices, and so you'll see a lot of activity as we move forward. I mentioned Heidelberg, where it sits; just came online in January. We're putting wells on now. And then we've got two more to add later in the year.

Very good assets internationally that are contributing a lot of cash flow to us and don't take a lot of reinvestment: Algeria, about $50 million of reinvestment on an annual basis to keep the production coming out of there. We've produced 2 billion barrels out of our Algerian assets as of last year, and still have another billion to go. We've got three huge facilities online, and they just continue to contribute to our cash flows and volumes.

Jubilee in Ghana's performed extremely well. The reservoir has done better than expected. And then the new TEN complex will be coming on at this third quarter of 2016 at 80,000 barrels a day. And that seems to be on time and on-budget at this point. So, those are two very important assets for us from stability, from cash flows, from low reinvestment rates in the existing assets, and so they're very valuable to us.

And then Mozambique, this is the huge discoveries that we have offshore in Mozambique, gas discoveries that we're trying to commercialize in the way of LNG. Just very quickly as to what's happening over there: the main things this year will be government agreements. We're not going to be investing a lot of capital this year. It's all focused on getting things right. As you get towards FID, and that means government agreements, means markets and means project finance. And some of those can be working in parallel. Some of them are dependent, like some of the project financing and the marketing agreements. You have to have certain government agreements in place.

So, we're advancing all of those without investing a lot of capital at this point. So, a gigantic asset. When the time is right and we've de-risked the decision for FID, so this gives us that opportunity to financially de-risk that decision, then we'll make a decision on the final investment here.

So when you look at the exploration side, we explored last year. As I mentioned, this year is going to be very similar. Three focus areas: West Africa, where we're going to be active at Paon and some exploration; Colombia, where we're going to come back and appraise our Kronos discovery; and Gulf of Mexico. Now, that's very similar to what we did last year. It's not going to be a huge number of wells, but are going to be really important wells. Paon will help to see whether we're going to advance that to development. Colombia is going to be de-risking further, what we found there. And Gulf of Mexico is going to be some appraisal work and potentially, an exploratory well.

So really, again, it's all about preserving and enhancing the value for 2016: making sure that we're not losing opportunities; that the quality assets we have are optimized as much as we possibly can; and where we have the opportunity, enhancing that value; focusing on our balance sheet, making sure that that is strong, and sets us up for the future when commodity prices do turn.

So with that, I will take a few questions.

QUESTION AND ANSWER SECTION

Q

Hi. I've got two questions. One is on Shenandoah. What kind of breakeven do you need there? What kind of price do you need for you to proceed with that? Or is it still a bit early? But what kind of – on the call, you guys said that $30 obviously doesn't go, but what price [ph] need (16:06) there? And then, on Heidelberg, kind of what are you expecting in terms of ramp-up? And where do you expect that to come in, sort of on an LOE basis? Thanks.

Robert P. Daniels
Executive VP-International & Deepwater Exploration

A

Everybody heard the question? On Shenandoah, I don't think that we have a price deck right now that says it would be economic at this, because right now, you're still in cost deflation, whether it's on drilling rigs, whether it's on construction costs and your services.

So, I think we need to get a match as to what we think, at time of sanction, the costs are going to be: what are we going to need in the number of wells, which we're not there yet. And so I couldn't give you one at this point, an absolute breakeven commodity price.

We're planning on appraising it this year. The Shenandoah Number 5 well will be drilled, and that'll be off to the east, again, trying to prove lateral extent, that kind of thing. We did appraise it last year. We had a successful well, 620 feet of pay in that. So, we still are advancing the project, but we're a ways away from a sanction at Shenandoah.

And at Heidelberg, I think we have two wells on now. We're going to bring a third well on very shortly, and then we have two more that come on through the year there. And Heidelberg Spar is an 80,000 barrel a day spar. We never thought we were going to get to the full 80,000 with just Heidelberg, but we have tieback opportunities in there, and we'll utilize that capacity as the opportunities present themselves.

Q

Could you just give us the breakeven for Heidelberg, please?

Robert P. Daniels
Executive VP-International & Deepwater Exploration

A

I'm sorry?

Q

Breakeven price, oil price, for Heidelberg?

Robert P. Daniels
Executive VP-International & Deepwater Exploration

A

We usually don't give out breakevens on individual assets. Clearly, it's an economic project. We did the design one/build two for Lucius. We saved $1 billion on the overall costs and saved what? About a year?

John M. Colglazier
Senior VP-Investor Relations & Communications

A

Year-and-a-half.

Robert P. Daniels
Executive VP-International & Deepwater Exploration

A

Year-and-a-half off the time. So that's just value that you create. So those are – and Heidelberg is a beneficiary of that.

John M. Colglazier
Senior VP-Investor Relations & Communications

A

Right. And remember, [ph] Diego (18:11), the other thing that we did was that we did that joint venture carrier arrangement, to where we were in essence carried all the way through the development process of the pr ojects. So our returns are going to be outstanding.

Robert P. Daniels
Executive VP-International & Deepwater Exploration

A

Yes?

Q

Yeah. Question back here. So we've heard a lot of presentations here this week on preserving the balance sheet and so on. And obviously, you have a big stake in Western Gas resources, particularly a very large ownership position in the GP. Their cost of capital has gotten pretty high, so it starts to raise a question about whether the dropdown story could be continued this year. So I mean, how are you thinking now about your stake ownership position in Western, in the GP? How are you thinking about maybe looking at what that dropdown trajectory might be for Western Gas resource? That would really be helpful; your thoughts on that?

Robert P. Daniels
Executive VP-International & Deepwater Exploration

A

Got an answer to that, John?

John M. Colglazier
Senior VP-Investor Relations & Communications

A

No, I think that's something I'd prefer to wait till next week on to talk about it, if you don't mind.

Q

I have a general question on costs. Obviously, you talked about the [ph] non-stack (19:24) question on Shenandoah. Shale costs, the industry has done a fantastic job and you guys, too. It's always, how long is a piece of

string? At some point, you think you can't get costs down, or lower the breakevens any further, and yet the industry is still managing to do that. So, maybe give us some general color on where you see the sort of breakeven envelope, not necessarily prices, but just the ability to improve, to lower that over time?

Robert P. Daniels
Executive VP-International & Deepwater Exploration

A

For the shales? Or for...

Q

Well, for shales and I wanted to follow on LNG, if there's any cost deflation there.

Robert P. Daniels
Executive VP-International & Deepwater Exploration

A

Well, on the shales, I think that everybody is focused on it. And so, if you did things the same way that you did it 2014, you may have gotten everything out you can. But everybody is now looking at it, all right, so what if we do things different? Would we use less profit? We'd do more slickwaters. This casing design change that we did in Wattenberg. Those type of thing, they will continue. I mean, you got people now that are not chasing rigs, drilling wells, but are focused on optimizing.

And they're going to come up with some really cool things. They're going to have scale that you can take across the field, whether it's on the production enhancement, whether it's on how you're actually completing these wells. And so, I do think there's still room to get more efficiencies, maybe not absolute costs, but that rolls through into the costs, out of the onshore.

In the deepwater, rigs have come down. If you're on long-term contracts, of course, you get the contractual obligations. Service costs have come down fairly significantly over the past six to eight months, maybe 20% to 30% in the total spread rate, which is about half of your day rate. And we think that that has room to go down further still. And then, of course, as you roll off contracted rigs and pick up uncontracted rigs, you're going to have a tremendous change in your cost structure. So, I think there's room for those costs to come down quite significantly over the next two to three years.

And then, on construction costs, when you look at the yards or any of the major EPC contractors, their books are drying up, and they're getting hungry and they would like to get the work. And so, we're seeing construction costs coming down. And so, I think that would roll through into something like a Mozambique.

Q

I mean, it's not often talked about the LNG, because we focus on shale and deepwater because they're closer in, but it feels like there could be some significant savings. I don't know if that is something that you've seen as you've done the feed work.

Robert P. Daniels
Executive VP-International & Deepwater Exploration

A

Absolutely. The initial feed work that we did and what we actually got in the way of bids, they came in essentially at the pre-feed cost for an extra two million tons per annum. So they upsized the facilities for the cost that were

estimated two years before, which meant the steel cost and everything else had come down, labor cost, and they were able to do that. So yes, we're seeing it already starting, but we expect more of that.

Q

And you would expect that cost curve to continue to fall over the next two years before FID or one-and-a-half years, how long it takes, or?

Robert P. Daniels
Executive VP-International & Deepwater Exploration

A

As long as – it depends on what on the environment is that we're working in. If all of sudden the commodity prices turn, we don't expect that, but if they did and activity level has picked up, then you'd see maybe a bottom. But as long as we're in this kind of an environment, you'd expect to see costs continue to come down. And we're going to keep working them. I mean, that's our job is to do it as efficiently as possible.

Q

And then one final question, CapEx flexibility is one of the levers that you've rationally done and said: look, at $30 oil, why should we develop stuff that's in portfolio which will have a much better return a few years out? Describe how much more flex you think there could be in the capital program if oil stayed lower for the next few years?

Robert P. Daniels
Executive VP-International & Deepwater Exploration

A

Yeah. We'll probably address that in quite a bit of detail next week rather than get into it here. But we're always looking at how we can do more with less. And so, we'll give some details on that next week.

Unverified Participant

Well, thank you very much, Anadarko. Thanks for everyone's time.

Robert P. Daniels
Executive VP-International & Deepwater Exploration

All right. Thank y'all very much.

Exhibit 104

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D. C. 20549

FORM 8-K

CURRENT REPORT
PURSUANT TO SECTION 13 OR 15(d) OF THE
SECURITIES EXCHANGE ACT OF 1934

Date of Report (Date of earliest event reported): March 1, 2016

ANADARKO PETROLEUM CORPORATION
(Exact name of registrant as specified in its charter)

Delaware	1-8968	76-0146568
(State or Other Jurisdiction of Incorporation)	(Commission File Number)	(IRS Employer Identification No.)

1201 Lake Robbins Drive
The Woodlands, Texas 77380-1046
(Address of principal executive offices)

Registrant's telephone number, including area code **(832) 636-1000**

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 7.01 Regulation FD Disclosure.

On March 1, 2016, Anadarko Petroleum Corporation (Anadarko) announced its 2016 capital budget and provided guidance for 2016. The press release is included in this report as Exhibit 99 and is incorporated herein by reference. This information shall not be deemed to be "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended (Exchange Act), or otherwise subject to the liabilities of that section, and is not incorporated by reference into any filing under the Securities Act of 1933, as amended, or the Exchange Act.

Item 9.01 Financial Statements and Exhibits.

(d) Exhibits.

99 Anadarko Press Release dated March 1, 2016.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

ANADARKO PETROLEUM CORPORATION
(Registrant)

March 1, 2016

By: /s/ CHRISTOPHER O. CHAMPION
Christopher O. Champion
Vice President, Chief Accounting Officer and Controller

EXHIBIT INDEX

Exhibit No.	Description
99	Anadarko Press Release dated March 1, 2016.

Exhibit 99

Anadarko Petroleum Corporation

NEWS

ANADARKO ANNOUNCES 2016 CAPITAL PROGRAM AND GUIDANCE

HOUSTON, March 1, 2016 - Anadarko Petroleum Corporation (NYSE: APC) today announced its 2016 initial capital expectations and guidance, concurrent with its 2016 Investor Conference Call.

2016 INVESTOR CONFERENCE CALL HIGHLIGHTS

- Reduces year-over-year capital investments by almost 50 percent[1]
- Expects higher-margin oil sales volumes to be flat year over year on a divestiture-adjusted basis[2]
- Doubles Delaware Basin recoverable resource estimate to more than 2 billion barrels of oil equivalent (BOE)
- Announces plans to monetize up to $3 billion of assets in 2016, with $1.3 billion announced or closed year to date

"In 2016, we will continue our disciplined and focused approach, preserving and building value by leveraging our best-in-class capital allocation, enhancing operational efficiencies and continuing an active monetization program," said Al Walker, Anadarko Chairman, President and CEO. "We are committed to again investing well within cash inflows from a combination of anticipated discretionary cash flow and our ongoing monetizations, with the expectation of also reducing net debt during the year. As we announced last week, we have already closed or announced monetizations totaling approximately $1.3 billion, and we expect our cash position to be further strengthened during the year through substantial cost reductions and additional identified monetization opportunities. We will also benefit from the recent action by our Board to reduce our dividend, which will provide approximately $450 million of additional cash this year."

2016 INITIAL SALES-VOLUME AND CAPITAL EXPECTATIONS

Initial 2016 Capital Expectations ($2.6 - $2.8 Billion)[1]

Billions		*Billions*	
By Area		**By Cash Cycle (E&P only)**	
U.S. Onshore	$ 1.1	Short Cash Cycle	$ 1.5
International	0.7	Mid Cash Cycle	0.5
Gulf of Mexico	0.7	Long Cash Cycle	0.5
Midstream & Other	0.2		

Note: All amounts are approximates.

Divestiture-Adjusted[2] Sales-Volume Expectations

	2016 Initial Expectations	2015
Total (MMBOE)	282 – 286	292
Oil (MBOPD)	308 – 313	312

U.S. ONSHORE

Anadarko's U.S. onshore activities will be reduced the most, by almost $2.5 billion in capital investments year over year, as the company preserves its opportunities, including in two of the highest-returning onshore assets in North America – the Delaware and DJ basins – for a more compelling price environment. The company is reducing its U.S. onshore rig count by 80 percent to five operated rigs, from an average of 25 in 2015, while focusing on its base production and retaining the flexibility to leverage its inventory of approximately 230 drilled but intentionally uncompleted wells. In the Delaware Basin, Anadarko plans to run four operated rigs, which will be directed toward delineation and lease maintenance rather than development activities. To date, the company's successful activities in this play have reduced well costs, identified additional prospective zones and doubled the estimated recoverable resources to more than 2 billion BOE. In the DJ Basin, the company expects to operate one rig, compared to seven in 2015.

GULF OF MEXICO

Anadarko's 2016 Gulf of Mexico program will focus on the company's capital-efficient tieback oil opportunities, as well as on advancing appraisal activities. By leveraging its existing infrastructure, Anadarko's tieback opportunities offer returns of more than 30 percent at today's strip prices. These activities will include tiebacks at Lucius, Caesar/Tonga and K2. In addition, Anadarko plans to advance existing discoveries through appraisal activities at Shenandoah and Phobos. One exploration well is planned at the Warrior prospect, which if successful, could be a tieback to K2.

INTERNATIONAL

In 2016, Anadarko's planned international activity will include efforts to advance its Paon oil discovery offshore Côte d'Ivoire toward potential development with one appraisal well, a drillstem test, and two exploration wells. Once activities are completed in Côte d'Ivoire, the rig is scheduled to return to Colombia to conduct additional exploration drilling activities. Offshore Ghana, the company expects to achieve first oil at the TEN complex in the third quarter of 2016. In Mozambique, Anadarko expects minimal funding in 2016 as it works three parallel paths toward a Final Investment Decision (FID) for its LNG project. These processes include securing the necessary legal and contractual framework, progressing more than 8 million tonnes per annum of off-take toward long-term sales contracts and advancing project financing.

Four pages of supplemental materials including the company's 2016 initial guidance, updated hedging positions and a reconciliation of divestiture-adjusted sales volumes are provided in the tables attached to this release.

(1) Does not include capital investments by Western Gas Partners, LP (NYSE: WES).

(2) See the accompanying table for a reconciliation of "divestiture-adjusted" or "same-store" sales volumes, which are intended to present performance of Anadarko's continuing asset base, giving effect to divestitures.

Anadarko Petroleum Corporation's mission is to deliver a competitive and sustainable rate of return to shareholders by exploring for, acquiring and developing oil and natural gas resources vital to the world's health and welfare. As of year-end 2015, the company had approximately 2.06 billion barrels-equivalent of proved reserves, making it one of the world's largest independent exploration and production companies. For more information about Anadarko and APC Flash Feed updates, please visit www.anadarko.com.

This news release contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Anadarko believes that its expectations are based on reasonable assumptions. No assurance, however, can be given that such expectations will prove to have been correct. A number of factors could cause actual results to differ materially from the projections, anticipated results or other expectations expressed in this news release, including Anadarko's ability to realize its expectations regarding performance in this challenging economic environment and meet financial and operating guidance; reduce its net debt; meet the objectives identified in this news release; consummate the transactions described in this news release and identify and complete additional transactions; execute the 2016 capital program; drill, develop and commercially operate the drilling prospects identified in this news release; achieve production and budget expectations on its mega projects; and successfully plan, secure necessary government approvals, enter into long-term sales contracts, finance, build and operate the necessary infrastructure and LNG park in Mozambique. See "Risk Factors" in the company's 2015 Annual Report on Form 10-K, Quarterly Reports on Form 10-Q and other public filings and press releases. Anadarko undertakes no obligation to publicly update or revise any forward-looking statements.

Cautionary Note to Investors: The United States Securities and Exchange Commission ("SEC") permits oil and gas companies, in their filings with the SEC, to disclose only proved, probable and possible reserves that meet the SEC's definitions for such terms. Anadarko uses certain terms in this news release, such as "recoverable resource," and similar terms that the SEC's guidelines strictly prohibit Anadarko from including in filings with the SEC. U.S. investors are urged to consider closely the disclosure in Anadarko's Form 10-K for the year ended Dec. 31, 2015, File No. 001-08968, available from Anadarko at www.anadarko.com or by writing Anadarko at: Anadarko Petroleum Corporation, 1201 Lake Robbins Drive, The Woodlands, Texas 77380, Attn: Investor Relations. This form may also be obtained by contacting the SEC at 1-800-SEC-0330.

# # #

ANADARKO CONTACTS

MEDIA:
John Christiansen, john.christiansen@anadarko.com, 832.636.8736
Stephanie Moreland, stephanie.moreland@anadarko.com, 832.636.2912

INVESTORS:
John Colglazier, john.colglazier@anadarko.com, 832.636.2306
Jeremy Smith, jeremy.smith@anadarko.com, 832.636.1544
Shandell Szabo, shandell.szabo@anadarko.com, 832.636.3977

Anadarko Petroleum Corporation
Financial and Operating External Guidance
March 1, 2016

Note: Guidance excludes 2016 sales volumes associated with pending East Chalk divestiture.

	1st-Qtr Guidance (see Note)			Full-Year Guidance (see Note)		
	Units			Units		
Total Sales Volumes (MMBOE)	74	—	76	282	—	286
Total Sales Volumes (MBOE/d)	813	—	835	770	—	781
Oil (MBbl/d)	311	—	316	308	—	313
United States	229	—	232	222	—	225
Algeria	64	—	65	59	—	60
Ghana	18	—	19	27	—	28
Natural Gas (MMcf/d)						
United States	2,250	—	2,290	2,030	—	2,060
Natural Gas Liquids (MBbl/d)						
United States	119	—	123	117	—	120
Algeria	5	—	7	5	—	7

	$ / Unit			$ / Unit		
Price Differentials vs. NYMEX (w/o hedges)						
Oil ($/Bbl)	(7.00)	—	(2.00)	(7.00)	—	(2.00)
United States	(8.00)	—	(3.00)	(8.00)	—	(3.00)
Algeria	(3.00)	—	—	(4.00)	—	(1.00)
Ghana	(3.00)	—	—	(4.00)	—	(1.00)
Natural Gas ($/Mcf)						
United States	(0.40)	—	(0.15)	(0.40)	—	(0.20)

Anadarko Petroleum Corporation
Financial and Operating External Guidance
March 1, 2016

Note: Guidance excludes 2016 sales volumes associated with pending East Chalk divestiture.

	1st-Qtr Guidance (see Note)			Full-Year Guidance (see Note)		
	$ MM			$ MM		
Other Revenues						
Marketing and Gathering Margin	15	—	35	145	—	165
Minerals and Other	45	—	65	185	—	205
Costs and Expenses						
	$ / BOE			$ / BOE		
Oil & Gas Direct Operating	3.00	—	3.15	3.20	—	3.40
Oil & Gas Transportation	3.40	—	3.60	3.55	—	3.75
Depreciation, Depletion, and Amortization	14.90	—	15.25	15.80	—	16.00
Production Taxes (% of Product Revenue)	8.0%	—	9.0%	8.0%	—	9.0%
	$ MM			$ MM		
General and Administrative	280	—	300	975	—	1,025
Other Operating Expense	25	—	35	55	—	65
Exploration Expense						
Non-Cash	60	—	80	350	—	450
Cash	50	—	70	280	—	300
Interest Expense (net)	205	—	215	840	—	860
Other (Income) Expense	50	—	60	200	—	225
Taxes						
Algeria (100% current)	70%	—	75%	70%	—	75%
Rest of Company (1Q 5% current; Total Year 10% current)	30%	—	40%	30%	—	40%
Avg. Shares Outstanding (MM)						
Basic	508	—	509	509	—	510
Diluted	509	—	510	510	—	511
Capital Investment (Excluding Western Gas Partners, LP)	$ MM			$ MM		
APC Capital Expenditures	800	—	900	2,600	—	2,800

Anadarko Petroleum Corporation
Commodity Hedge Positions
As of March 1, 2016

	Volume (MBbls/d)	Weighted Average Price per barrel					
		Floor Sold		Floor Purchased		Ceiling Sold	
Oil							
Three-Way Collars							
2016							
WTI	65	$	41.54	$	53.08	$	62.25
Brent	18	$	47.22	$	59.44	$	69.47
	83	$	42.77	$	54.46	$	63.82

Interest-Rate Derivatives
As of March 1, 2016

Instrument	Notional Amt.	Reference Period	Mandatory Termination Date	Rate Paid	Rate Received
Swap	$50 Million	Sept. 2016 - Sept. 2026	Sept. 2016	5.910%	3M LIBOR
Swap	$50 Million	Sept. 2016 - Sept. 2046	Sept. 2016	6.290%	3M LIBOR
Swap	$500 Million	Sept. 2016 - Sept. 2046	Sept. 2018	6.559%	3M LIBOR
Swap	$300 Million	Sept. 2016 - Sept. 2046	Sept. 2020	6.509%	3M LIBOR
Swap	$450 Million	Sept. 2017 - Sept. 2047	Sept. 2018	6.445%	3M LIBOR
Swap	$300 Million	Sept. 2017 - Sept. 2047	Sept. 2020	6.569%	3M LIBOR
Swap	$250 Million	Sept. 2017 - Sept. 2047	Sept. 2021	6.570%	3M LIBOR

Anadarko Petroleum Corporation
Reconciliation of Divestiture-Adjusted Sales Volumes

Average Daily Sales Volumes

	Oil & Condensate MBbls/d	Natural Gas MMcf/d	NGLs MBbls/d	Total MBOE/d
Quarter Ended March 31, 2015				
U.S. Onshore	167	2,232	129	668
Deepwater Gulf of Mexico	46	221	6	89
International and Alaska	107	—	7	114
Divestiture-Adjusted Sales	320	2,453	142	871
Divestitures*	15	285	1	63
Total	335	2,738	143	934
Quarter Ended June 30, 2015				
U.S. Onshore	173	1,976	122	625
Deepwater Gulf of Mexico	57	113	7	83
International and Alaska	87	—	6	92
Divestiture-Adjusted Sales	317	2,089	135	800
Divestitures*	1	265	1	46
Total	318	2,354	136	846
Quarter Ended September 30, 2015				
U.S. Onshore	160	1,870	109	581
Deepwater Gulf of Mexico	55	158	7	88
International and Alaska	84	—	5	89
Divestiture-Adjusted Sales	299	2,028	121	758
Divestitures*	2	158	1	29
Total	301	2,186	122	787
Quarter Ended December. 31, 2015				
U.S. Onshore	164	1,940	105	592
Deepwater Gulf of Mexico	54	115	6	80
International and Alaska	96	—	6	102
Divestiture-Adjusted Sales	314	2,055	117	774
Divestitures*	2	13	1	5
Total	316	2,068	118	779
Year Ended December 31, 2015				
U.S. Onshore	165	2,003	116	615
Deepwater Gulf of Mexico	53	152	7	85
International and Alaska	94	—	6	100
Divestiture-Adjusted Sales	312	2,155	129	800
Divestitures*	5	179	1	36
Total	317	2,334	130	836

* Includes EOR, Bossier, Powder River Basin CBM, and East Chalk (transaction pending).

Exhibit 105

S&P Global
Market Intelligence

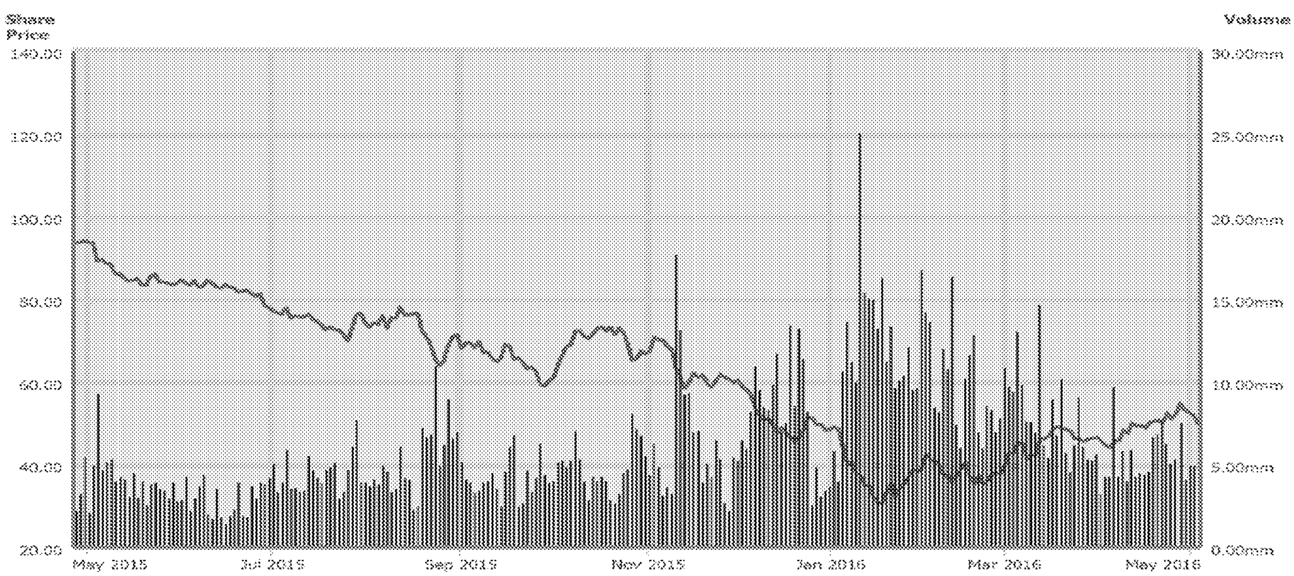
Exhibit
545

Anadarko Petroleum Corporation
NYSE:APC
FQ1 2016 Earnings Call Transcripts
Tuesday, May 03, 2016 1:00 PM GMT
S&P Global Market Intelligence Estimates

	-FQ1 2016-			-FQ2 2016-	-FY 2016-	-FY 2017-
	CONSENSUS	ACTUAL	SURPRISE	CONSENSUS	CONSENSUS	CONSENSUS
EPS Normalized	(1.18)	(1.12)	NM	(1.00)	(3.81)	(1.27)
Revenue (mm)	1781.69	1674.00	▼(6.04 %)	1787.50	8024.87	10401.06

Currency: USD
Consensus as of May-03-2016 10:55 AM GMT

Stock Price [USD] vs. Volume [mm] with earnings surprise annotations



- EPS NORMALIZED -

	CONSENSUS	ACTUAL	SURPRISE
FQ2 2015	(0.52)	0.01	NM
FQ3 2015	(0.74)	(0.72)	NM
FQ4 2015	(1.09)	(0.57)	NM
FQ1 2016	(1.18)	(1.12)	NM

Table of Contents

Call Participants

EXECUTIVES

A. Scott Moore
Former Senior Vice President of Midstream & Marketing

Darrell E. Hollek
Former Executive Vice President of Operations

James J. Kleckner
Former Executive Vice President of International and Deepwater Operations

John M. Colglazier
Investor Relations Professional

R. A. Walker
Chairman & CEO

Robert G. Gwin
President

Robert P. Daniels
Former Executive Vice President

ANALYSTS

Arun Jayaram
JP Morgan Chase & Co, Research Division

Brian Arthur Singer
Goldman Sachs Group Inc., Research Division

Charles Arthur Meade
Johnson Rice & Company, L.L.C., Research Division

David Martin Heikkinen
Heikkinen Energy Advisors, LLC

David Robert Tameron
Wells Fargo Securities, LLC, Research Division

David William Kistler
Simmons & Company International, Research Division

Douglas George Blyth Leggate
BofA Merrill Lynch, Research Division

Edward George Westlake
Crédit Suisse AG, Research Division

Evan Calio
Morgan Stanley, Research Division

James Jan Sullivan
Alembic Global Advisors

Jonathan Douglas Wolff
Jefferies LLC, Research Division

Paul Benedict Sankey
Wolfe Research, LLC

Scott Michael Hanold
RBC Capital Markets, LLC, Research Division

Unknown Analyst

Presentation

Operator

Good morning, and welcome to the Anadarko Petroleum First Quarter 2016 Earnings Conference Call. [Operator Instructions] Please note, today's event is being recorded. I would now like to turn the conference over to John Colglazier. Please go ahead, sir.

John M. Colglazier
Investor Relations Professional

Well, thank you, Rocco. Good morning, everyone. We're glad you could join us today for Anadarko's First Quarter 2016 Conference Call.

I'd like to remind you that today's presentation includes certain forward-looking statements and non-GAAP financial measures and to let you know that a number of factors could cause results to differ materially from what we discuss today. So I encourage you to read our full disclosure on forward-looking statements and the GAAP reconciliations located on our website and attached to yesterday's earnings release.

In just a moment, I'll turn the call over to Al Walker for some brief opening remarks, but first, I'd like to introduce Brian Kuck, who has rejoined our Investor Relations team and will be available to assist you with questions, along with the rest of the team. I'll also remind you that we have additional detail on our quarterly ops report available on our website. And following Al's prepared remarks, we'll open it up for questions with Al and the rest of the team. Al?

R. A. Walker
Chairman & CEO

Thanks, John, and good morning. I think it almost goes without saying that things feel better today than they did 90 days ago, both for our industry and for investors. The very fragile energy capital markets we've seen for most of the first quarter appear to be stabilizing, the outlook for commodity prices are improving and I think for industry, our operating environment is definitely strengthening. As a company, our employees delivered very solid results despite the challenges in the first quarter. As a company, we're poised to take advantage of the market as opportunities develop.

If I could, let me take a moment and recap what we achieved in the first quarter. We announced a capital plan that was 50% lower than 2015 and 70% lower than 2014. Our cap plan produces oil volumes that are expected to be flat year-over-year as well as on an exit rate basis. We monetized $1.3 billion of assets with another $700 million expected in the second quarter. We will continue to be an industry leader in active portfolio management.

We reduced our dividend 81%, which we believe will save us $450 million of cash per annum, and we positioned our company to be more successful financially and operationally in the years ahead if prices stay lower. Our savings from these efforts, we believe, will increase our ability to be more cost-efficient and should provide more than $350 million of costs in savings per annum. We issued $3 billion of fixed income securities to refinance our 2016 debt and the first 125 -- well, pardon me, $1.25 billion of our 2017 debt at very attractive rates and terms.

Operationally, we continue to set a very high bar. As you've seen, our reductions in various cost savings, LOE per barrel improved 22% in the first quarter versus the prior year. Our liquids mix continues to increase and our well costs in the DJ were reduced 11% from the year before to a level today of about $2.4 million per well. The Delaware Basin also has seen really good efforts as well with cost reductions where their wells are costing us $1 million per well less quarter-over-quarter to about $6.2 million per copy.

What can you expect from us through the balance of the year? Do not expect us to increase our capital spending this year even if oil exceeds $50. We could reallocate some of our savings in our budget to increase capital to certain plays like the Delaware Basin. We'll be very patient as we look beyond 2016 to

a sustained higher price environment to increase capital and return to a growth mode, if warranted. Our operations report includes various highlights across our portfolio, and I encourage you to take a look at that for more details as your time permits.

Our employees have done an incredible job, as I mentioned earlier, during this first quarter, maintaining a focus on safety and productivity, meeting the challenges of a workforce reduction without losing focus on our operating results, being aggressive with portfolio management and diligent in our divestiture process. They've consistently and constantly look for ways to improve our business and manage through this volatile cycle successfully.

Working to improve our financial position is something we think about every day, and I think the most recent example of that is the receipt of our cash tax refund approaching $1 billion through a lot of good efforts. Our combined efforts to improve our cash inflows will position us through the balance of the year to reduce our net debt.

In closing, I think we've taken the right actions in the first quarter to position Anadarko for success. We do believe we're going to continue to see improving commodity prices, but however, near-term volatility remains a concern. Our industry and company are both in a much better place than we were 90 days ago, and it gives us renewed optimism this cycle is on a track to much better investment returns.
With that, why don't we open it up for questions?

Question and Answer

Operator

[Operator Instructions] Our first question comes from Evan Calio of Morgan Stanley.

Evan Calio
Morgan Stanley, Research Division

Al, you mentioned you don't expect to increase the capital in 2016. Can you just discuss how you could reallocate the capital, presumingly -- presumably to the iDUCs? And what's the source of funds within the budget that could reallocate? And then a follow-up, please.

R. A. Walker
Chairman & CEO

Well, I think the comments I've made about savings are quite impressive. I think we continue to believe that we'll find things to reduce our capital intensity. As such, we would redeploy that primarily into the Delaware Basin in West Texas.

Evan Calio
Morgan Stanley, Research Division

Right. And then that'll be from an iDUC basis or do you mean from a rig -- a new rig -- or raising -- changing the rig count?

R. A. Walker
Chairman & CEO

No. I mean, I made reference to a couple of places where we're reducing our cost per well pretty significantly in the first quarter. I think as we continue to improve our abilities to execute our business, you'll see us not increase our capital but reallocate those savings into places like the Delaware Basin.

Evan Calio
Morgan Stanley, Research Division

Great. And my follow-up is on Heidelberg. I know one of the holders had commented on initial data from first producing wells and tests on other development wells that were indicating production rates materially lower than expectations, another 3 wells online. Can you address these comments as it relates to production costs or the resource estimate at Heidelberg?

R. A. Walker
Chairman & CEO

Well, I might ask, if I could, Jim Kleckner, to address those more specifically. And I think with that, Jim, if you would.

James J. Kleckner
Former Executive Vice President of International and Deepwater Operations

Yes. This is Jim. The Heidelberg facility came online 3 months ahead of schedule. I just want to compliment the project team for being able to achieve that goal. If you recall last year, there were a lot of interruptions in the Gulf of Mexico with loop currents and still managed to get that facility up and running ahead of schedule with just a seamless hook up in commissioning schedule. We've got 3 wells currently producing. Those 3 wells are running about a combined 15,000 barrels a day. We have 2 wells that are on planned on the second half of this year and we're going to target those wells in sections of the reservoir that we think will have very good deliverability. And we should be looking towards production ramping up to 40,000-plus barrels a day towards the end of the year in 2017.

Evan Calio

Morgan Stanley, Research Division

Will Phase 2 -- is Phase 2 something that would ultimately bring you to full utilization of the facility? Or how should we think about that?

James J. Kleckner
Former Executive Vice President of International and Deepwater Operations

Well, once we complete Phase 1, we'll evaluate the performance of those wells. And then Phase 2, which would be extension to the South, could be implemented and that could then increase production further. But we haven't decided on Phase 2 yet. We're going to finish Phase 1 before making any decisions.

Operator

And our next question comes from Doug Leggate of Bank of America Merrill Lynch.

Douglas George Blyth Leggate
BofA Merrill Lynch, Research Division

Al, the comments about putting cash back to work, you're not in any rush, I wonder if I could take the question a different way and talk about the balance sheet. Where do you really want the balance sheet to get back to? And I guess, specifically, with WGP having recovered somewhat, I think it's up about 100% from the lows, what is -- is that back on the table now as a source of funds? And I've got an operational follow-up, please.

R. A. Walker
Chairman & CEO

Well, let me, if I could, ask Bob Gwin to address your question specifically.

Robert G. Gwin
President

Doug, your question on WGP. I don't know that I'd say it's back to the table. Our view is that it's a ready source of liquidity at a point in time. Certainly, it would be more attractive to us as something we would consider, given where it's trading now relative to the kind of unrealistic lows earlier in the space as the MLP sector took quite a hit. But frankly, we understand the go-forward plans around the MLPs because largely, Western Gas and WGP's fortunes are pretty closer related to our activities in the DJ and in the Delaware and to a number of other producers in the Delaware that are customers of Western Gas is there. So we're going to take a look at the value of that asset over time, just like we do with the rest of the assets in our monetization program. And if we think that relatively fair value can be achieved, then we'd consider it. But we don't have any current plans to sell WGP. It's not one of the assets that we're currently working on or that our comments on the $700 million of pretty substantial progress over the last couple of months was related to.

Douglas George Blyth Leggate
BofA Merrill Lynch, Research Division

And on the balance sheet, any specific targets, Bob?

Robert G. Gwin
President

No targets that we're setting out there. I think that if you look at the monetization target that we put in place and the guidance around the underlying numbers, you'd look to build cash. Clearly, during the second quarter, Al referenced the tax refund that we received. We'd be building cash during the second quarter and early on through the end of the year. Certainly, well north of $1 billion and whether or not it's north of 2 or more, largely tied to our decisions around asset sales. And as we said before, those -- obviously, the cash has the result of lower net debt and our expectation is that we would take a pretty significant portion of the cash that we build and apply it toward actual debt reduction including the last $750 million associated with our 2017 maturities. In an earlier press release, we pointed out that that

$750 million would be repaid from cash on hand, and that cash would be generated through additional monetizations.

Douglas George Blyth Leggate
BofA Merrill Lynch, Research Division

Okay. My operational follow-up is actually on Shenandoah. A couple of things, I guess, I'm interested in there. You obviously have a partner sell down their interests, although not specific on Shenandoah exactly. It looks like it was a fairly low number. You guys have preemptive rights. So I'm wondering what your thoughts are there, both when it comes to the value of your position, but also the fact that we're now 5 appraisal wells in. What are you seeing there that is taking so long to appraise it, if you like? Is it really just scale, something unique to the reservoir that may make it a little bit more challenging to get a sanctioned [ph] decision? And I'll leave it there.

R. A. Walker
Chairman & CEO

Doug, understandable questions. I think the first part of the question, I'll address and ask Bob Daniels to talk to you more specifically about what you're seeing from the appraisal perspective. The pref period is running. I think you should expect that we will, hopefully, be communicating something towards the end of that pref period. And I think your observations, I can't find any fault with them.

Robert P. Daniels
Former Executive Vice President

Yes. Doug, on the wells and the appraisal program, it's partly scale, it's partly -- some of the complexities that we're seeing out there, mostly on the imaging side of it, not necessarily that we're seeing lots of bad surprises. Although we did, through our most recent wells, realize that there are some faults that were poorly to not imaged in some of the seismic data that we're going to have to build into a potential development plan. And so that means that we needed a few more appraisal wells to make sure that there's not any more compartmentalization as we move across. So those are the issues that we're looking at. I'd say it's mostly based around the quality of the image in the sub-salt and making sure that what we're seeing or interpreting is actual reality, and so we're drilling the 5-well now to the west and pushing that downdip quite significantly to prove up of those volumes as we move over. And then with success there, we'd move over even farther to the -- I'm sorry, to the east, and we'd move over even farther to the east with the #6 well. So those are what's happening there. The biggest issue on timing and making sure that we have the data is -- this can be a big development if we move forward with it. And it's going to be an expensive development and you want to know what the well deliverabilities are going to be, what your actual resources range are going to and you want to come up with a solution that actually makes sense for this resource. And it's in a technically challenging environment from a pressure standpoint. So we have to make sure we get it right before we take those final decisions. So that's kind of what we're working on right now.

Douglas George Blyth Leggate
BofA Merrill Lynch, Research Division

I appreciate your answer, Bob. Al, if I may, just a quick follow-up for you on this. ConocoPhillips is also -- is publicly selling its deepwater position. I'm just curious, could you [indiscernible] position where your working interest gets to a scale in Shenandoah, basically, do another capital efficient farm down? Or is that unlikely at this point?

R. A. Walker
Chairman & CEO

You kind of broke up in the middle of it, Doug, so I'm going to be sure I understood your question. Are you asking me, would we be interested in increasing our working position where we and ConocoPhillips have prospects or appraisal development together?

Douglas George Blyth Leggate

BofA Merrill Lynch, Research Division

No. I'm thinking -- okay, I've got a bad cellphone line. I was thinking more about a repeat of the Heidelberg-Lucius model. If you, for example, not only Marathon's position but Anadarko's as well as Conoco's position was available as well, do you see Anadarko getting to a scale where you could ultimately farm down for development dollars?

R. A. Walker
Chairman & CEO

Well, we haven't had direct conversations with Conoco on that topic. I think your observation is sort of what is our playbook is a fair one. I think as we continue to understand the things that Bob just made reference to better than we do today, we would certainly consider options in the future. But I think, at this juncture, to assume that we would be interested in increasing our working interest position at the size that, for instance, ConocoPhillips is at, without additional information, probably would be in the category of not likely.

Operator

And our next question comes from Arun Jayaram of JPMorgan.

Arun Jayaram
JP Morgan Chase & Co, Research Division

I had one question on just the U.S. oil production guidance. Despite some of the concerns on Heidelberg, you guys did reiterate your U.S. oil production outlook for the full year, but you did guide to lower volumes in Q2. Can you just go through why U.S. oil volumes will be down a little bit in Q2?

R. A. Walker
Chairman & CEO

Well, let me start, if I could, around with the comment that Heidelberg is actually performing relative to the guidance that we gave to investors through the course of the year. So we -- maybe different from you -- don't see Heidelberg performing any differently than we anticipated this year. As the wells that we expect to drill and have produced to date, they've performed as we anticipated. So the comments and the concerns associated with Heidelberg leave me a little bit in the category of scratching my head. Now as it relates to oil volumes through the course of the year, as I'm sure you can appreciate in a capital-intensive business, onshore, we have certain places where we're adding to capital and certain places we're taking away. But I think we have given you largely the types of volumes we anticipate through the year. The one thing that we can't anticipate and schedule well is liftings. And liftings sometimes happen either to our advantage or disadvantage. But I think the thing that we still feel like, and I made this in my earlier comments, is that we believe, for the year, we will be flat year-over-year on all volumes and probably, just as importantly, on an exit rate basis, so no change from our perspective on that.

Arun Jayaram
JP Morgan Chase & Co, Research Division

Okay. That's helpful. And my follow-up, Al, is just looking at Mozambique, there are some press reports that big oil is looking at taking a stake in ENI's Area 4. I was just wondering if you could talk about some of the implications if you saw someone like Exxon in Area 4, do you view that as positive, negative or neutral in terms of Anadarko's ability to develop your discoveries in Mozambique?

R. A. Walker
Chairman & CEO

Well, let me answer you this way. And I guess until we have a new partner in the unitization process of Prosperidade in Mamba with Areas 1 and 4, we work very hard every day with the partners that we know about. And to extent that changes, then I'll make a comment at that time.

Operator

And our next question comes from Paul Sankey of Wolfe Research.

Paul Benedict Sankey
Wolfe Research, LLC

It sounds very simply as this your first aim is to pay down some debts and then at a given price you'll resume growth spending focusing on the U.S. Within that overall basic outline, I was wondering your previous success as deepwater explorers feels like it's somewhat on hold now. Can you talk about where deepwater exploration and I guess, what separates it between the GOM and international? When will that come back? Is it at a price? Is it sometime in the future? I'm struggling to understand where that fits in the kind of new world of oil.

R. A. Walker
Chairman & CEO

Yes. Understandable question, Paul. Thank you for asking it. I think, as we've talked about this year, we see a number of tieback opportunities in the Gulf of Mexico that have very attractive potential rates of return if they're drilled out successfully. You may see those categorized as exploration or exploitation. Certainly, the existence of infrastructure allows us to go out and drill something today that is an exploration well, with the ability to tie it back to existing infrastructure and reduce the development costs. I think the area that you're focused on, and accurately so, is if we're looking at true new infrastructure to support exploration efforts, are we likely to do that in an environment where we're drilling below salt? And I think, today, as we made the comment on the last call, that's a pretty challenging bit of arithmetic. So I think we'll continue to look for opportunities in the near term, for which we've given some good detail in our ops report and other color commentary around it, that we think in the Gulf of Mexico, we have really good opportunities to tie back to infrastructure to take advantage of our exploitation, exploration and development that we see there. Outside the U.S., we look at places where, basically, in a post-salt environment where the well costs are substantially less, as I know you fully appreciate. And there, as we have before, we see exploration creating option value for the future. That turned out to be a pretty good premise for which we think that our business strategy, and I know you know it quite well, but when we think about short-term, medium-term and long-term cycling of cash, cycling of cash for us in the short term has to produce extremely good rates of return and good characteristics of cash-on-cash. The medium- and long-term cycling is more to create that option value and enhanced value for the future. Whether we take that to production and development will be dependent upon the price environment at that time. So I'm not -- I mean, I'm not probably answering your question as specifically as you answered it, but I am trying to approach it from the standpoint it still fits in the business model, which I think we've done a pretty good job of since 2007 of staying within. And that's just simply thinking about the cycling of cash, the rates of return for the near term, thinking about the value added from the long term, from an option standpoint, staying within cash inflows with our investing and being mindful of really aggressive portfolio management in order to enhance either the rates of return or the value creation. And -- maybe if I could have Bob Daniels talk a little bit about what we're seeing specifically in other areas with our exploration beyond just the quantitative assessment I gave you.

Robert P. Daniels
Former Executive Vice President

Yes. Paul, I'd say that we're not on hold. We've slowed down like we've done in all sectors of our business given the cash flows that we have now in the capital program. But this year, we're in Côte d'Ivoire drilling appraisal wells and then we're going to do a DST at our Paon complex. And then follow that up with 2 exploratory wells to the south in exploration acreage we have adjacent to that. So that's all are going to be very interesting. The rig from there, we'll move back into Colombia and do an appraisal well on our Kronos discovery and follow that up, hopefully, next year, with some additional work down in the Fuerte area. Meanwhile, we're acquiring a huge -- the second half of a huge 3D up in COL area and the deepwater Colombia. We really are excited with what we're seeing on the first phase and looking forward to getting that second phase done and putting that whole program together. And then meanwhile in the Gulf, Al mentioned the -- all the tiebacks and all the -- near infrastructure work that we're doing this year. And that is similar to what we're doing at Phobos where we have discovery in the lower tertiary that we're going to try to get on appraisal later in the year. So we've got quite a few things that are going on. And

when you look out to the future, 16 million acres in the deepwater of Colombia, we picked up -- we're apparent high bidder, 4 new blocks in the Gulf of Mexico. So we're continuing to move forward, but it's got to be within the context of the price environment that we find ourselves. And we're trying to set ourselves up for the future as we come out of this. So that's where we're focused on and we still got a very good program going.

Paul Benedict Sankey
Wolfe Research, LLC

I understand that. And I guess, successful exploration is value adding at almost any oil price and so it becomes a question of risking the exploration. I think what you just said to me is that there's an issue first in thinking about risk between pre- and post-salt, and that would become a bit of a geographic question. To be specific, at Heidelberg, we've -- in the past, we've seen issues with the reservoirs in the Gulf of Mexico, deepwater Gulf of Mexico, is there a problem there and does that change your risk assumptions, especially given, I guess, we've also got the issue of government risk and the attraction of the U.S. against international and anything else you could help -- add to help me think about that would be very useful.

James J. Kleckner
Former Executive Vice President of International and Deepwater Operations

Yes. This is Jim, and I'll answer the question specifically regarding Heidelberg. We know this area of the Gulf of Mexico very well. It's a Miocene section that is on the same trend as our Caesar/Tonga field and then on the Tahiti field. And we know those reservoir rocks, the quality of them very, very well. And I think what distinguishes Heidelberg is, it's structurally -- it was little more complex because of the steepness of the dipping beds up against the salt well. But we anticipate, just like Caesar/Tonga, which we brought online and Phase 1 was -- is in the process of being completed. These wells have very good flow characteristics with good porosity and permeability. So we anticipate good performance of our additional wells at Heidelberg. As an example, and part answer to the prior question, we initiated Phase 2 of Caesar/Tonga last year. And so we see additional extension of that field once we've resolved some of the reservoir well targeting locations and then the flow performance issues. So anticipate, just as we did in Caesar/Tonga, along the same trend, we'll do the same thing at Heidelberg.

Robert P. Daniels
Former Executive Vice President

And Paul, just to answer the question about the Gulf versus international and those types of things. We look at all of those types of things on a risk/reward basis. And I think what Al was getting at is, the Gulf of Mexico pre-salt tends to be very expensive, they're deep, they're complex wells and so when you start looking at the reward for new developments out there, they've got a lot of capital that you got to put to work. And we see other places in the world that perhaps we can find that those similar type of resources that maybe are not quite as expensive to development. And in this price environment, we're paying attention to that very closely.

Operator

And our next question comes from Charles Meade of Johnson Rice.

Charles Arthur Meade
Johnson Rice & Company, L.L.C., Research Division

I wonder if I could go back to one of the themes you brought up in your prepared comments when you're talking about the environment for both Anadarko and the industry being a little more comfortable now than it was 3 months ago. And my question is does that also extend to the buyers that you're seeing in that A&D market? I know you guys are looking to sell a lot of things and I'm curious if people have more appetite there. And if you could, if there's any differentiation you see between maybe operating companies or PE-backed companies or some of the traditional financial buyers that you've sold down to in the past?

R. A. Walker

Chairman & CEO

Charles, I think both Bob and I had mentioned either in our earnings call about 90 days ago or our analyst call in March that we continued to see a pretty strong interest from people looking to buy properties from Anadarko. I think the broader property market certainly has a pretty good depth of private equity chasing it. But I think the other thing, and I continue to highlight this, is that when we look to monetize an asset, many times, we are a seller of choice from the standpoint that you're not taking on operational problems that you might be taking on with less capitalized companies or companies that don't have the operational history and success that we've had. So I think the fact that we've been a good, prudent operator for a long time, we're a brand name, if you want to call it that, in our space, when we choose to redeploy capital by exiting a particular property, you're not taking on problems that you might with a smaller or less well-known company. And that, to date, has inured to our benefit as you've seen a very successful effort in the last 2 years to monetize properties into, I think, anyone would describe as a very difficult environment. Now Bob Gwin deals with this day in and day out, and I would really like for him to please add to those comments.

Robert G. Gwin
President

Charles, the only thing I'd add is that the economics you asked about is, Al's comment on the improving environment is that we've seen that read through. I think, in particular, yes, on the gas side. We've -- we had a number, we've mentioned that a number of the assets that we're focused on, considering the sale of today are gassy. And with the improvement in the forward curve, we've seen some strengthening in the interests for those assets. And it doesn't take a whole lot of improvement on the price side to get some materially better economics at the outside level. And so as you would expect, you see that read through in terms of the level of interest and in terms of the bids that we received. And obviously, on all these assets, we're evaluating the sell case versus the hold case. And so the math gets better for us and then the question is what's the value in the eye of the beholder and how aggressively might they put capital on rigs to work on assets that are going to struggle to be allocated capital against our other very strong primarily oilier opportunities.

Charles Arthur Meade
Johnson Rice & Company, L.L.C., Research Division

Got it. That's helpful. And then if I could ask a question about the horizontal wells or maybe the concept of the horizontal wells offshore that you mentioned, offshore Côte d'Ivoire. Is that the kind of thing that we might be -- we might see in the future in your Gulf of Mexico tiebacks? Or is this more the kind of thing that's applicable to these unconstrained stratigraphic plays that you're chasing in the rest of world?

R. A. Walker
Chairman & CEO

Yes. Charles, I'll address it. There's going to be applications for it around the world. I don't think that's going to be like in the onshore U.S. where it becomes the prevailing methodology of drilling these wells. But in the case of the Paon wells and the development of that field or the appraisal of that field, we have very, very good imaging of the reservoir section using some in-house techniques that have allowed us to, ahead of the wells, essentially predict within a plus or minus 10% accuracy, the gross sand count and so we were able to really place the well very, very accurately. And what it allows us to do then is also more reservoir section for DST that will give us data earlier on deliverability, conductivity, those types of things. So there was an application here that sped up the evaluation process. But the only reason we could do it is because we knew very, very accurately what to expect in the wellbore and how to place the lateral section, so it worked very well. We're doing the reentry of the #3. We'll also have a high-angle sidetrack out of it to monitor the DST results, but it will have applications, but it's not going to be tremendously widespread.

Operator

And our next question comes from Scott Hanold of RBC.

Scott Michael Hanold

RBC Capital Markets, LLC, Research Division

Al, I hate the kind of badger you on this, but with Heidelberg, certainly, there had been some obvious concern with what that's producing. And can you just talk in generalities what might be the differentiation between how you all looked in -- looked at that coming into the year versus your partner?

R. A. Walker
Chairman & CEO

Well, I think it's twofold. I can't speak to what our partner provided in the way of guidance for the year, but I'll reiterate what I said earlier and that is, Heidelberg has produced exactly the way we've provided guidance to The Street. It's not underperformed and it's performed in line with what we thought the wells would do. So therefore, it doesn't seem to create, for us, the problems it seems to be creating for others that maybe haven't taken as much time to look at it as we'd like them to. I think the other thing is you have to realize is that we have a very limited cost basis in this development. If you recall, a few years ago, we farmed down our interest there and almost all of our development cost has been borne by a third-party. In fact, there's still carry left associated with that farm-down. So therefore, if you're thinking about impairments, if you're thinking about balance sheet treatment, this asset would be carried on our books very differently than maybe some of our partners. So if people would take those 2 together, they might understand that we're not as concerned about Heidelberg as certainly it appears to be. Some people are as it might relate to our partner, but from our perspective, Heidelberg has produced in line with what we anticipated it would do for the year and relative to the way in which we provided guidance in The Street.

Scott Michael Hanold
RBC Capital Markets, LLC, Research Division

Okay. So if I'm hearing you clear, relative to what you think the research recovery from the existing wells are going to be and the productivity from your base case, there really is no change to what the wells are showing at this time.

R. A. Walker
Chairman & CEO

Not for what we anticipated to be at the productivity of those wells for 2016.

Scott Michael Hanold
RBC Capital Markets, LLC, Research Division

Okay. What about beyond that?

R. A. Walker
Chairman & CEO

Well, as we look at the estimated ultimate recovery with -- as we put new wells on and we see performance, then we'll continue to update our model in terms of what we think the ultimate recovery will be from Heidelberg. I'm sure you've seen from our operations report, we have wells we anticipate drilling through the balance of this year. And as we see those wells come on and have some performance, we'll have additional commentary in quarters to come.

Scott Michael Hanold
RBC Capital Markets, LLC, Research Division

Okay. Understood. And my follow-up is in the Marcellus. You all had a pretty big jump in production. I'm making up an assumption that's from your operating partner, bringing some volumes online. Can you give a little color around what to expect there and what the pricing situation looks like there? Because I think M3 pricing has improved and you all have exposure to that.

R. A. Walker
Chairman & CEO

Yes. Let me say, Darrell and I will tag team you on your question. And let me just say, yes, your non-operated volumes are, as you well know, are beyond your control. And certain times in any quarter we'll have a third-party volumes that will exceed what we anticipated going into it, and that certainly is the case in the Marcellus. But specifically, some of your questions instead of me answering it, why don't I let Darrell?

Darrell E. Hollek
Former Executive Vice President of Operations

Yes. Just a little follow-through on Al's comments there, is if you looked at the third and into a little bit of the fourth quarter last year, we did have some volumes curtailed up in Marcellus because of where pricing was. And if you look at where we are in the first quarter, we were producing while we had no curtailments. And so that's really the variance you see as we came out of last year into this year. And -- but just note that we're not investing any additional capital in there right now, so it would be our anticipation that we'll just continue as we're going and you'll probably recognize some decline as we go through the rest of this year.

Scott Michael Hanold
RBC Capital Markets, LLC, Research Division

Okay. And do you all have exposure to M3 up there?

A. Scott Moore
Former Senior Vice President of Midstream & Marketing

So this is Scott Moore. We do not. Our volumes are sold into Tennessee and Transco, primarily. And so the issue on TETCO has not directly impacted Anadarko.

Operator

And our next question comes from Ed Westlake of Crédit Suisse.

Edward George Westlake
Crédit Suisse AG, Research Division

Yes, I'm going to start with a bit of a flier, which you may not be able to answer, but you mentioned good depth on the PE markets and lots of interest on the gas side. Obviously, you've got quite a large gas footprint in terms of production in East Texas, North Louisiana, Marcellus, some of the Eagle Ford and, obviously, Mozambique's already come up. Is the market for gassier assets deep enough in general for you to do something more transformative with the debt burden, which still seems too high?

R. A. Walker
Chairman & CEO

Well, let me address part of the question and ask Bob to address part of the question as well. If you recall, both in March as well as when we reported our first -- or our fourth quarter and prior year results in January, we said at that time that we still believe that there's -- depending upon the private equity firm, there are firms that have a very fundamental view that natural gas is a better place to invest than oil. They look at the activation costs of liquids and oil versus what they think is a fairly good market for natural gas and a good market from those folks, as I listen to them, is they feel very good about the ability of natural gas to run to $3 or more. From where we are today, they see that product -- if you want to call it a product -- but just refer to it as product, having better sustainability in the near term with less volatility than oil. So yes, you do have people who have fundamentally different views between the 2 hydrocarbons for things they want to invest in. And that's why we continue to see really good inbounds when we take properties into the market and evaluate the potential to be sold. As it relates to the comment about the balance sheet and the debt, I'm going to let Bob answer that one.

Robert G. Gwin
President

Ed, we don't generally discuss assets, particular assets, that we're looking at selling prior to at least getting into the market with them and then, hopefully, even later in the stages once we see what the interest in those assets is and whether or not we might be interested in selling them. So I don't want to comment on the particular assets you mentioned. I don't think you should look for us to do something that you characterize as transformative, but we've got beyond the math that we've laid out there in terms of the closed and announced transactions and the $1.3 billion in the first quarter, or as of that March 1 Investor Call and another $700 million now. We put a range out there of $2 billion to $3 billion, so that leaves roughly another $1 billion that we're working on. And as we've said before, that's a risked number. So the gross number we're working on is a bigger number. There are some sizable assets in there and some small ones. And how that portfolio of assets sale [ph] candidates comes together is going to be based upon the relative demand for and interest in those assets from not just private equity but industry players. So as the year progresses, there'll be greater clarity on that. And I think -- the plan that we've laid out, I think, puts us in a position relative to what we believe is, even with the moderate recovery, still a relatively low commodity price environment; we believe, positions us for a pro forma appropriate leverage position.

Edward George Westlake
Crédit Suisse AG, Research Division

Okay. Then a smaller one, just on the obviously great perks in the Delaware, the $5.2 million projected pad development from a 4,500 foot short lateral. A couple of sort of comments around that. Longer-lateral testing, maybe if there's any color you could provide in terms of your efforts on the EUR side. And then on the cost side, can you lock-in some of these lower costs? Because obviously, as the industry gets to work, the costs may start to move back higher.

Darrell E. Hollek
Former Executive Vice President of Operations

Yes, this is Darrell. We do quote everything by the short lateral. It's just easier to do, but there's no doubt that with our land position we are doing some of the mids and longs. And they do give us better economics, if you will. The fact that we're down to $6.2 million a well, I can tell you that's better than we thought we'd be doing at this point. And so it gives us pretty clear line of sight to the $5.2 million when we get to the pad drilling situation. So we feel really good about that. In terms of actually locking-in those services, at this point, I have to say we have actually recognized further benefits from not having that locked in. And so part of the savings, as Al mentioned earlier, that we're recognizing still this year that may not have been anticipated is what's going to allow us to continue doing a few more activities out in Delaware than we anticipated as well.

R. A. Walker
Chairman & CEO

But Ed, I will take your comment. You're right. As prices, hopefully, continue to make progress over the next 1.5 years, it's likely, at some point along on the way, you'll see a service cost reaction. And I don't think you're wrong by saying, "At what point would you like to think about locking things in?" I think sustainability of higher prices, for us, is sort of a watchword. It's not without a whole lot of leap of comment [ph] that volatility still concerns us. So consequently, we'll be a little cautious as we look at an improving price environment as well as trying to lock-in costs.

Darrell E. Hollek
Former Executive Vice President of Operations

Yes. The one other comment I'd add is we've shown significant reductions, but it's not all associated with the service cost, if you will. A lot of those reductions have to do with just how fast we're able to drill these wells and some of the completions we're doing now. So a lot of it has to do with the efficiencies of our activities and not completely with just a reduced cost structure.

Operator

And our next question comes from Dave Kistler of Simmons & Company.

David William Kistler
Simmons & Company International, Research Division

And following up a little bit on the Delaware and DJ cost savings. In your ops report, you highlighted that the majority of that was being driven by completion cost savings. Can you give us a little bit more detail in terms of the drivers of that, whether it's substituting different products in there, whether it's purely efficiencies. Just increased detail would be very helpful.

Darrell E. Hollek
Former Executive Vice President of Operations

Well, again, this -- again, this is Darrell. It depends on where you're looking at. If you look at Delaware, probably half the cost savings, half of that $1 million, actually came from the drilling side; and about 300 in the completion side and about 200 on the facility side. And so it's not all in the completions. We're seeing it in all facets. And a lot of it is our cycle time. And in some cases, we're still getting, like I said, a reduction of service costs. And so that's contributing to it as a well, but to a large extent, it's really our cycle times in all these areas that's getting us there. And not so different in the DJ as well, where the reduction isn't quite as much, but if you look at the past few years, we've made a lot of strides there. And so the fact that we've gone from about $2.7 million to $2.4 million, it's not as big, but those incremental cycle time reductions is really what's getting us there.

David William Kistler
Simmons & Company International, Research Division

No, no doubt, very impressive. Switching over to the line of sight to the $700 million of divestitures in Q2. Can you talk a little bit about maybe what the EBITDA impact of that could be or any sort of operating cost impact of that and maybe anything with respect to geography targeted or hydrocarbons targeted?

R. A. Walker
Chairman & CEO

No. A very good try, Dave, but until we get the assets actually sold, we'll probably just keep mum about that. And then once they're closed and we come up to give you an update on guidance, we'll adjust both the volumes as well as the cash impact from that.

Operator

And our next question comes from Brian Singer of Goldman Sachs.

Brian Arthur Singer
Goldman Sachs Group Inc., Research Division

Can you talk about production mix in your key shale plays and how you expect that to evolve going forward? The Permian oil mix has increased; and wondered if -- where you see that heading, particularly if you commit more down the road. If you commit more capital and drill more there, do you expect a flattening, an increase or a decrease in the well mix? And then also if you could comment on the Eagle Ford and the Wattenberg as well.

R. A. Walker
Chairman & CEO

I think, generally speaking, as we've said before, quite a few quarters, we anticipate that our oil and liquids mix will be going up. Some of that is through the capital expenditures being focused today at new -- in completely and uniquely oil and liquids. Some of it also has to do with the gas divestitures that we've talked about, that we've realized on and certain assets that we anticipate selling through the course of this year. So either through organic or inorganic means, I think you can anticipate our oil and liquids will be a higher percentage of our overall mix. And I'll let Darrell, if I can, talk a little bit about what he's seeing in the particular basins you made reference to.

Darrell E. Hollek
Former Executive Vice President of Operations

Brian, as we talk about Delaware, we can't be real specific there because of our big acreage holding there, but as we continue to delineate across there, I think in all cases we're pretty excited. But as we've mentioned before, as you go east to west, as we go west, our EURs are definitely picking up, but so are the GORs. But the nice thing is you're still sitting at about 60% oil on the west side with a bigger GOR -- or with the bigger EURs. But even the east side of our field, we're about 70% oil, and we're really excited about that piece as well. So I think, over time, it'll prove that it'll increase our oil percentage as a whole in the U.S., particularly for onshore, but as it's particularly to this asset, it's just hard to predict every year what we're doing just because of where we're drilling across all the acreage right now.

Brian Arthur Singer
Goldman Sachs Group Inc., Research Division

Got it. And then the Wattenberg and Eagle Ford, where we've seen the mix become a little bit less oily, is that just a function of infrastructure and reduced drilling activity? Or is there something more to that?

Darrell E. Hollek
Former Executive Vice President of Operations

Well, I think, in Wattenberg, you can expect more of the same. It's just a matter of when we pick up our activities again, but obviously that's closer to 50% oil. And I think you'll see that hold true for the balance. And the Eagle Ford, we don't actually have any activity levels planned in the near term, but -- so I don't think you'll see that percentage changing as well. It's -- we'll pretty much be producing what we have right now until prices come up.

R. A. Walker
Chairman & CEO

And Brian, this is Al. I know you know this. Our Eagle Ford production has a mix there that doesn't compare the same as you might see for some of the other companies you cover. Ours has always been a fairly lean oil and, even with that, a higher-gravity oil relative to some of the folks to the north and east of us.

Brian Arthur Singer
Goldman Sachs Group Inc., Research Division

Yes, absolutely, great. And then I figured I'd throw this one in. You were -- Al, you were pretty vocal and clear on your last call regarding where issuing equity stood within your priorities, low on the list. And I wondered if you can just talk in the context of being in a better environment now versus 90 days ago both for oil prices and APC share price, whether your views have changed at all.

R. A. Walker
Chairman & CEO

Well, we certainly don't see a need to issue equity for any balance sheet restoration. So I mean I -- the comments that I've made and others of our management team have made will continue to hold true. Even as we've gotten into a better environment both for the commodity outlook as well as where share prices have traded versus 90 days ago, this comment still holds.

Operator

Our next question comes from David Tameron of Wells Fargo.

David Robert Tameron
Wells Fargo Securities, LLC, Research Division

Just a couple follow-ups. Al, when you think about the service industry and kind of the -- if we get in a rebound scenario here, do you think anything changes, as far as the structure of service contracts and what you guys are able to do as far as locking it in post this? In a recovery-type scenario, does anything change there, or are we just back to the same old 2-year-rate type of thing and locking it in?

R. A. Walker

Chairman & CEO

Well, I mean, we would certainly be willing to entertain thoughts that the service providers might have. Historically, they've not really wanted to go out for too long. And I think we as industry, not just Anadarko, have not really wanted to go out for too long. Whether we move from a spot basis to some contractual basis will be Darrell's call with his folks as we see that market evolving, but Darrell, I don't think today you're too motivated. Are you?

Darrell E. Hollek
Former Executive Vice President of Operations

No. As I mentioned earlier, again, we're still seeing some benefits of reduced costs. So I don't think now is the time, but it -- but we will continue to look at it this year and into next year as to what may be best. But there's other things available to us in terms of whether we can try to consolidate some of our efforts, and so we'll be -- we'll continue to be tough and with some of the service sector to figure out what's the best way forward.

David Robert Tameron
Wells Fargo Securities, LLC, Research Division

Okay. And then just Darrell, one follow-up. When you start talking about pad drilling and the ability to get down to that $5.2 million, how much does pad drilling save you on a kind of per-well, per-location type basis? What's your best guess?

Darrell E. Hollek
Former Executive Vice President of Operations

I'm sorry. I'm missing your point. I mean it's $1 million from where we are today. Obviously, we're not in a pad drilling situation today, so our best guess right now is $6.2 million to $5.2 million. And so that would be $1 million a copy. And so I think that's very doable, from what we're seeing today; and probably some pressure to bring that lower.

David Robert Tameron
Wells Fargo Securities, LLC, Research Division

Okay, so all that -- the $1 million savings is all on just due to pad drill [ph]. Okay, all right. Great.

Darrell E. Hollek
Former Executive Vice President of Operations

Yes, yes, yes. That would be B, C and E [ph]. That's right.

Operator

And our next question comes from John Rugelon [ph] of Societe Generale.

Unknown Analyst

Two quick ones from me. Colorado Supreme Court just negated local communities' ability to limit drilling activity. I know you work very well with the communities within Colorado on the DJ, but does this make your life a little bit easier with that Supreme Court decision?

R. A. Walker
Chairman & CEO

Well, we were certainly happy that the Supreme Court in Colorado saw the issue correctly, so I think, for now, yes would be the answer.

Unknown Analyst

Okay. And regarding the Delaware, you just increased your resource size materially. Do you have enough infrastructure? Or should we plan you to -- you and Western Gas perhaps to have more build-out of the infrastructure so you can capture those resources?

R. A. Walker
Chairman & CEO

Well, as we have done in the Delaware Basin, much like we did in the DJ Basin, we've tried to pace our midstream build-out with our upstream. If we get into the situation where we believe the Delaware Basin provides us attractive places to create rates of return and good cash-on-cash characteristics, you can anticipate we'll pace our midstream spending to keep up with the upstream.

Operator

And our next question comes from James Sullivan of Alembic Global Advisors.

James Jan Sullivan
Alembic Global Advisors

Most of the big strategy stuff has been asked and answered. I just want to get into a little nitty-gritty one and, well, a kind of a question from the Q here. Obviously, you guys had to post some collateral against your credit derivative liabilities in the quarter or more of it as a result of the Moody's downgrade. And you talked about that. Am I reading the Q correctly that, net of that collateral, there remains $1.1 billion of net credit derivative liability? And is there -- a, that's kind of the first thing. And the second is, how do you guys assess the risk of having to post any further collateral? Is there a triggering event that would do that, I mean, another downgrade or something that would be kind of unlikely? Or is it something that is a decision that lies with your counterparties? Any color on that would be great.

R. A. Walker
Chairman & CEO

Sure. We used about $600 million in cash to post collateral that was related to the Moody's downgrade. Most of that's related to individual [indiscernible] with various banks and derivative counterparties. We also -- the one other effect that is kind of a collateral-oriented event related to the Moody's downgrade is various of our transportation agreements that have credit rating-related triggers. We've generally been able to satisfy those with LCs and a little bit of cash here and there. Obviously, there's still some room. There's room for improvement or additional cash postings as underlying value of the derivative moves around. Relative to your question of further downgrades, if we retain investment-grade ratings with the other rating agencies, then there wouldn't be any subsequent triggers. Certain is there's a structure with the higher of your ratings and certain with the lower of your ratings. And so the ones with the lower of the ratings are the ones that are resulting in a cash need during the quarter, which we funded. And currently, that cash isn't on the balance sheet, but in theory it could certainly come back.

James Jan Sullivan
Alembic Global Advisors

That was just what I'm looking for. And then just back high level for a second. Can you guys comment on your view of the ethane market generally? Obviously, the Rockies assets have been in pretty deep interjection for a while, but there's been a lot of talk now about prospects for reduced rejection [ph] late '16, '17 as enterprise and some of the crackers come on. Do you guys just have a general macro view on that, that you want to offer us?

A. Scott Moore
Former Senior Vice President of Midstream & Marketing

This is Scott Moore. I will say 2 things. First of all, the ethane market is improving, with about 0.5 million barrels a day of demand coming on between exports and cracker additions, as you mentioned. You're seeing that in the ethane upgrade relative to the residue pricing that has some premium. There is still some longer-term challenges with the productive capacity relative to demand growth.

Operator

And our next question comes from David Heikkinen of Heikkinen Energy.

David Martin Heikkinen
Heikkinen Energy Advisors, LLC

Thinking a lot bigger picture, Al and Bob. You all do a really good job measuring your company performance, and you're pretty rate-of-return driven. How would you think about the rate of return on the roughly $900 million of capital invested in 1Q and kind of distribution from midstream return versus upstream return?

R. A. Walker
Chairman & CEO

Well, David, I think, when we look at a midstream return from an APC perspective, that might be different than a Western Gas. So if I could just stay with Anadarko only for a minute because typically, in the past at least, when we make an upstream investment, we think about the cost of also getting that to whatever is the delivery point, so that midstream build-out is a part of the upstream spend. So it would be a rate of return that would include getting that product into a market. Now that's different than Western Gas, and I know you fully appreciate that. That's why, going back to 2008, we saw those 2 markets valuing the assets differently. And why we put Western Gas in place as a result, we felt like it just really gave us a lot of optionality around 2 distinct assets. Although, from the standpoint of the investment, if you can't move a hydrocarbon into a market, then you haven't completed the cost of completion. So when we look at whatever we're doing new; or whatever Darrell may be, as an example, is thinking about incrementally in the Delaware Basin, that build-out, if it's on our nickel, would include that rate of return bundled with the upstream. Now as Western Gas evolves in its life cycle and becomes larger and in many cases, particularly say for instance, in the Permian, where Western Gas has a lot of stand-alone third-party business, then that becomes a little bit different equation. And maybe with that, if I could, I'll let Bob just approach it a little bit with Darrell by saying that you do have a bifurcation where Western Gas has its own rates of return and Anadarko has its own rates of return. But we do think about the process, I mean gathering, in a vacuum pretty much the way I just described it. And Bob, I don't know if you have anything you'd like to add.

Robert G. Gwin
President

I think the only thing I would add is that, the rates of return to Anadarko, we look at on a full-cycle basis, including the subsequent sale of those assets, those midstream assets that Anadarko develops, to Western Gas. And the full-cycle economics to Anadarko are quite attractive on that midstream investment. And then of course, Western is very competitive in terms of its rates of return under primarily cost-of-service agreements with Anadarko and third-party producers. Western's economics are self-evident in their own financials. And they'll report earnings, I think, tomorrow.

Darrell E. Hollek
Former Executive Vice President of Operations

The only thing I'd add to that, this is Darrell, is that the -- we have an added benefit, as WES, particularly as it continues to take on third-party volumes. And in Delaware, they're doing that in a big way, but Anadarko gets the benefit as that infrastructure gets moved throughout that whole Delaware Basin. There's places where we get to take advantage of it just because it gets there before we're actually developing some of our own acreage.

Robert G. Gwin
President

Does that address what you were curious about?

David Martin Heikkinen
Heikkinen Energy Advisors, LLC

Yes, that's exactly -- I was just -- that segregation and thought process is what I was curious about, as we've spent some more time on it recently. That's helpful. And then on the exploratory side, really I don't have experience with horizontal deliverability and deepwater reservoirs. Can you talk about what your modeling expectations would be? And then can you think about any of the appraisal results and impact on size for the -- in Côte d'Ivoire?

Robert P. Daniels
Former Executive Vice President

Yes, David, the #5 well was drilled between the discovery and #3. And it came in exactly as we had prognosed, about 100 feet true vertical thickness. The advantage with the horizontal is that you got to see a lot of that section in a lateral sense, which confirmed our seismic interpretation. Our EEI volume would have said the exact same thing. And really, the deliverability issue around the #5 is to get as good a flow rate as quick as we can to send a pressure pulse to the 1 and 3 so that we can prove up connectivity. So we wanted as much reservoir section open to give us those high volumes and a good pressure drawdown pulse that would send -- that we could then monitor because that's a key question that we have to have answered before we would move into a development phase is, what is the connectivity of the reservoir. So there were reasons beyond the actual ultimate production of this field that we put a horizontal well here because it's going to accelerate the evaluation during the appraisal phase and get us better data quicker. And so that's one of the main reasons that we did it in this case.

David Martin Heikkinen
Heikkinen Energy Advisors, LLC

How long a lateral was it?

R. A. Walker
Chairman & CEO

It was a little over 3,000 feet.

Robert P. Daniels
Former Executive Vice President

Yes, 3,000 feet.

David Martin Heikkinen
Heikkinen Energy Advisors, LLC

Of reservoir, okay. And any idea on size for Paon now with the -- this well and what would be a good production rate?

Robert P. Daniels
Former Executive Vice President

I don't think beyond what we've said before. Nothing has changed with this well. It just confirms what we'd originally thought. I think that the key questions now are, what is the deliverability? What's connectivity? And are there any kind of boundaries that maybe we haven't seen? And so we'll get all of that information, or a lot of that information, from these -- this DST and monitoring.

Operator

And our next question comes from Jon Wolff from Jefferies.

Jonathan Douglas Wolff
Jefferies LLC, Research Division

Better late than never. I don't want to keep up -- take up too much time, but Gulf of Mexico seems to be evolving into sort of a, for the industry, into more of a tieback strategy where there's a lot of upfront payment to create a facility. And then you can reap benefits by potentially gathering volumes for others; and/or if reservoir performs better than you think, you get the capacity yourself. Kind of point [ph]

number one on that. And then second, are we out of Miocene inventory in the U.S. Gulf of Mexico from a scalable standpoint? And then thirdly, can you talk about the rig rolloff schedule and how that might apply to a partner risk in terms of farm-downs and getting your interest to the right level so you don't have any CapEx creep?

R. A. Walker
Chairman & CEO

Okay, John, we'll tag team you with those 3 questions. I'd only start by saying having infrastructure in the Gulf of Mexico definitely separates us from many, not -- but not all of our peers. It allows companies like ourselves to be able to look to commercialize opportunities in this price environment at attractive rates of return that we wouldn't be able to even consider without the leverage of that infrastructure. Consequently, as we think about the infrastructure we have today, we're pretty comforted by the fact that it gives us that kind of optionality. And I -- whether it's for our own volumes, as you described, or for the production handling agreement that we would have in place to move that for others, we see that as a real strategic advantage for us. And I might ask Jim to handle the second part of your question and if Bob Daniels would, the third part.

James J. Kleckner
Former Executive Vice President of International and Deepwater Operations

So the question around the economics and the inventory, I think, I'll address from what we have in our existing fields. And as Al stated, those tiebacks provide very good opportunities because they're generally high-flow-rate wells with very little connection costs to the existing subsea infrastructure. In a lot of cases where we have the infrastructure already installed and we have available processing capacity and pipeline takeout capacity, we can lever that infrastructure, which has already been depreciated not only with our own equity opportunities, as we've mentioned, in Caesar/Tonga and some of our infield wells in Lucius, but also with other tiebacks that may be close proximity to our hubs. And so oftentimes, you'll find other operators who have had discoveries and maybe not as large to justify a greenfield development but have tieback capability within distance to us. We then will negotiate a process handling agreement. So those opportunities are out there. And we continually seek those, as well as operators seek those tiebacks to us. Regarding the Miocene opportunity after what we currently have identified, I'll let Bob address that from an exploration standpoint.

Robert P. Daniels
Former Executive Vice President

Yes, from -- John, from an exploration standpoint, I don't see that the Miocene inventory is exhausted in the Gulf of Mexico. We just had a discovery last year at Yeti in the Miocene. We're drilling several wells this year, both tiebacks and one which is really an exploratory well around our K2 area called Warrior, which is a very good Miocene prospect. We're the apparent high bidder on 2 prospects, 4 blocks, in the most recent lease sale which were Mio-Pliocene prospects. So we see still potential out there for not only tieback opportunities but for potential stand-alone exploratory wells. So we're continuing to work that.

Jonathan Douglas Wolff
Jefferies LLC, Research Division

Would you consider -- is it in your thought process to build or to have an FPSO that maybe is a little big for your needs with that view that there -- that you're in a good neighborhood? Or does...

R. A. Walker
Chairman & CEO

I'm not sure that, that's probably the best use of our balance sheet or our capital. I think the reason that we chose to do what we did at Heidelberg is that we used a design capability that we had with Lucius that allowed us to build an identical type of spar at about $1 billion less than we would have otherwise. And so we might have taken the view, if you think about it in that context, that if we had excess capacity, we weren't going to worry about it, but that was only because we were able to really reduce significantly the costs to build that spar and the delivery of that spar.

Jonathan Douglas Wolff
Jefferies LLC, Research Division

Got it. Rig rolloffs and rig risk to -- risk of farm-downs, of interests in a tough environment; or dropouts, like in the case of Marathon. I guess there's another partner, but...

James J. Kleckner
Former Executive Vice President of International and Deepwater Operations

Jon, in answer to your question on rig rolloffs, we have rigs under contract right now that extend at various dates. And those rigs are -- the first one expires in the first part of 2017. Then we have a second rig the rolls off in the last quarter of '17. And then subsequent rigs roll off in the years of '18, '19 and '20. So we manage that rig inventory along with our exploration development opportunities and manage our partner groups so that we have support of our drilling prospects and the development activities that we take with our partnership groups. So we would anticipate those rigs rolling off contract when the contracts are due. There may be some cases where we take a holiday with a rig, but we don't anticipate that in the schedule as you see it right now.

Jonathan Douglas Wolff
Jefferies LLC, Research Division

Okay. Is 35%, 40% a good number for a comfort level in terms of working interest?

R. A. Walker
Chairman & CEO

Yes, I'd say 35% to 40% is sort of a relevant range for us, Jon. And we may take plus -- and I can use Paon as an example. We might, as we are today, be sitting on more than that, but if we choose to go to development and sanction the project, our approach would be pretty similar from our playbook. We would be looking for a partner to reduce our working interests and having our capital either monetized or carried as the case may be.

Jonathan Douglas Wolff
Jefferies LLC, Research Division

Okay. Sorry, just one quick one because I'm so highly interested. Northeast PA, you said no curtailments in 1Q. It's a little different message. Cabot had similar comments. The industry hasn't invested much in 2, 3 years. Is there any case for a tightening of the Northeast PA market just on its own merits without having to worry about new expansions out of the basin?

A. Scott Moore
Former Senior Vice President of Midstream & Marketing

This is Scott Moore again. I would say, in the first quarter, we did see about a $0.10 uplift in our sales prices because the Transco Leidy Southeast project into service. So that was about 0.5 b [ph] a day capacity being added. It didn't move the basin pricing up a lot. The pipelines are still fairly fully utilized. And really the next big relief would come from the Atlantic Sunrise Project. The potential delay of Constitution is not particularly helpful. So I think it's going to remain challenged, and we do look forward to those projects coming forward.

R. A. Walker
Chairman & CEO

And appreciate the interest today and wish everyone the best. And we'll look forward to talking to you in 90 days. Thank you.

Operator
And thank you. The conference has now concluded, and we thank you all for attending today's presentation. You may now disconnect your lines, and have a wonderful day.

Exhibit 106

S&P Global
Market Intelligence

Anadarko Petroleum Corporation
NYSE:APC
Company Conference Presentation

Wednesday, May 11, 2016 1:00 PM GMT

Exhibit
330

Table of Contents

Call Participants

EXECUTIVES

Ernest A. Leyendecker
Former Executive Vice President of Exploration

Unknown Executive

ANALYSTS

Robert S Morris
Citigroup Inc, Research Division

Unknown Analyst

Presentation

Robert S Morris
Citigroup Inc, Research Division

Here this morning with the first session. Very pleased to have Ernie Leyendecker, Senior VP of International Exploration for Anadarko, presenting this morning. And you know the format. We're going to have 5-, 10-, 15-minute overview, and then we'll open it up for Q&A. It's meant to be interactive, so everybody, feel free to add jump in and ask questions.

But as most of you know, we have a buy rating on Anadarko. They just reported earnings last week, very good results. And we put a note out on that. But without further ado, I'm going to turn it over to Ernie and let him give the presentation.

Ernest A. Leyendecker
Former Executive Vice President of Exploration

Thanks, Bob. Good morning, everybody. Thank you very much for having us. We're happy to be here, particularly with this glorious weather we're having here in Boston. So it's good to be here.

Really wanted to open this morning just with a few thoughts around our highlights from the first quarter and the achievements we made in the beginning of this year, and I thought it was noteworthy to mention a few things to remind the audience and the people here. Because we think they're quite remarkable.

First of all, earlier in the quarter, we announced our capital plan for the year, which was a 50% reduction in cost of capital year-over-year from 2015 and actually, 70% reduction in capital from 2014, all while leaving oil volumes flat year-over-year and particularly exiting quarter-over-quarter at the end of 2016. So that was one achievement.

Secondly, we reduced our dividend, as many of you probably know, saving -- cutting 81%, saving approximately $450 million or so on a go-forward basis per annum. We also announced a number of monetizations in the first quarter, $1.3 billion worth of monetizations in the quarter, which, again, we continue to be active managers of our portfolio as we have historically done, which is critical for us to continue to balance our cash inflows with our cash outflows, provide this liquidity and flexibility and shore up the balance sheet a little bit.

We've also, subsequent to that, talked about another $700 million worth of monetizations, which we're working on. We hope to close in the second quarter, bringing the total at the end of the second quarter to somewhere around $2 billion or so, with a target to achieve somewhere between $2 billion and $3 billion worth of asset monetizations over the course of 2016.

We also, in the first quarter, optimized our workforce, reducing our costs and positioning ourselves better operationally and financially to weather the lower-for-longer period in our environment, saving roughly $350 million or so per annum or so. So between the dividend reduction and the cost savings on the G&A side, a material amount of savings on a go-forward basis that continue to give us more flexibility and reduce our cost structure.

And then we issued $3 billion worth of bonds to refinance our -- all of our 2016 maturities and some of our 2017. And that was quite a remarkable achievement in light of things going on in the ratings agencies, and so we're happy that we were able to issue those at what we continue to believe are investment-grade company ratings.

So -- and then finally, we continue to increase our liquids mix as we have achieved first production at one particular field in the Gulf of Mexico, at Heidelberg and continue to have full production from Lucius. We're anticipating first production from another international field in Ghana called TEN in the third quarter of this year. So liquids content keeps improving over the course of the year, which lets us basically exit the year with flat oil volumes.

And then finally, additional cost savings and reductions in our onshore program. We continue to work on that -- the cost structure, particularly at DJ Basin, where we've reduced our cost by about 11% year-over-year for new wells as well as in the Delaware Basin, where we reduced our cost by about $1 million or so. So our copy DJ Basin well is now running about $2.4 million per well, and our copy prototype well, the Delaware, is running about $6.2 million. And we're still not drilling on pads in the Delaware. So we're still doing the appraisal delineation of the entire Delaware Wolfcamp while we continue to build out our midstream there.

So I thought those were noteworthy accomplishments, which I will start with just to remind the audience of what we think was a significant amount of work that the team has done over the course of Q1. And of course, we anticipate a equivalent type of noteworthy events to happen in Q2. And looking forward to having discussion today with you, Bob, and everyone on what you'd like to talk about.
So with that, I think I'll leave it there and turn it back to you, Bob.

Question and Answer

Robert S Morris
Citigroup Inc, Research Division

Okay. Great. Let me just kick it off with the first question. You mentioned that you hoped to close another $700 million in asset sales during the second quarter. How has the market improved? I know there's a lot more out there that you could sell if you wanted to. Given the move up in oil price, is the market improving for selling assets? Are you seeing better opportunities? Or how is that developing?

Ernest A. Leyendecker
Former Executive Vice President of Exploration

Well, I think we continue to receive a lot of inbound traffic on a lot of our assets because we believe we're operator of choice and so we lead a lot of our assets. And given the diversified asset portfolio we have, there always seems to be someone who has a particular interest in a particular geographic or geologic area. So we still see it as fairly healthy marketplace, and we believe we're going to -- we're confident we're going to be able to achieve the $700 million of additional monetizations, and then others, perhaps, as we go through the balance of 2016.

Robert S Morris
Citigroup Inc, Research Division

On the international front, you've obviously had some great success in the past: offshore Ghana, with TEN coming on this year, as you mentioned; offshore Côte d'Ivoire and you had a great gas discovery offshore Mozambique. Different companies are taking different tacks in this environment. Some claim that it's a better environment to explore because costs are lowering. There's less competition. On the other hand, it's more and more difficult to find oil. We found a lot of gas line companies who found a lot of natural gas around the world, but it's more and more difficult to find oil. Going forward, do you guys see it as a better opportunity for exploration internationally to find oil? Or would you rather slow it down and kind of focus on what you've already discovered?

Ernest A. Leyendecker
Former Executive Vice President of Exploration

Well, Bob, being an explorer, I would like to continue to explore, but we all have to take in consideration the current environment. So a couple of things to note within the international organic exploration world. It's a challenging thing to find oily basins, obviously. There's lots of opportunity for international gas. There's plenty of gas, as in particular, in places where we operate, obviously, in Mozambique, where we made one of the most remarkable discoveries in the last 20 years. So finding gas is probably a little bit less challenging than finding oil, and that's one of our greatest challenges, to find oily basins. We do find ourselves a very attracted to oily basins. But as you look at the global landscape, they appear to be somewhat limited. So obviously, we love the Gulf basin, the basin that keeps on giving. I think there's -- we love the Cretaceous margin in West Africa, where we're active in CI, obviously have discoveries in Ghana on production in TEN that's nearing first production. But the rest of the globe, we continue to scour and look for access and opportunities, for oil opportunities, for oil exploration. But in the current environment, we're focusing our international and offshore exploration and appraisal activities more of a limited sense than we have in the past. So you mentioned Côte d'Ivoire. Currently, we're drilling and we're in an appraisal campaign in Côte d'Ivoire on our CI-103 block at our Paon discovery, where we just recently finished drilling an appraisal well, a horizontal appraisal well, which in itself is remarkable. Because it's the first time we have applied horizontal technology to the offshore environment as an operator, as Anadarko as an operator. That is game changing for us in the sense that we look at trying to continue to reduce the cost structure and improve our economics. So drilling a 1,000-meter lateral in the Paon reservoir gives us access to higher deliverability, exposes us to more reservoir contact, so -- and potentially, higher EURs. So today, we're back to drilling -- we're reentering another well, which we previously drilled, an appraisal well. We're drilling another lateral on that. We will subsequently put gauges in that, and then we'll go updip of the appraisal well we just drilled, and we'll put gauges in

that. Then we'll come back to the well in the middle of the 2 wells that were discovered and conduct a drillstem test and an interference test to look at the reservoir producibility, deliverability, connectivity and continuity. So application of advanced technology is something that we continue to look for and apply all around the globe, including offshore. We're also going to replicate what we've done in Mozambique with interference testing to try and understand how wells communicate to each other within the reservoir. So our international and offshore exploration and appraisal program is really focused on: one, appraisal activities in Côte d'Ivoire, and then we'll follow up very quickly with 2 exciting exploration wells where, I call it, we're going to try and extend the trend. So effectively, we're going to drill a couple of wells, one on CI block 528, called Rossignol; and one on CI block 527, called Pelican. Same section basically, just one depositional system removed from the Paon discovery, so petroleum system, relatively derisked. I'm very excited about that. And then we will move that rig back to Colombia and continue our campaign in the Gran Fuerte area, where we opened up a new frontier, a gas frontier there. Beyond that, in the Gulf of Mexico, we continue to appraise our Shenandoah -- our fantastic Shenandoah discovery and apply the rest of our rig fleet to tiebacks and near-field infrastructure, exploiting our hub-and-spoke focus in the Gulf.

Robert S Morris
Citigroup Inc, Research Division

Yes. You're going to drill a horizontal gas well onshore Algeria this year, too. Am I correct?

Ernest A. Leyendecker
Former Executive Vice President of Exploration

No, I don't believe we're going to drill a horizontal well in Algeria. We've been looking for a long time at...

Robert S Morris
Citigroup Inc, Research Division

I know there's a lot of gas potential that you talked about in the past in onshore Algeria. But...

Ernest A. Leyendecker
Former Executive Vice President of Exploration

There is a significant amount of gas potential in the Berkine Basin. And we do have -- we are talking about securing a position in a couple of different countries in North Africa. But we don't -- we're not ready to drill any horizontal wells and test them. We don't have a mandate to do that. We have been following and as a technical adviser, have been helping Sonatrach evaluate a couple of wells they drilled in a basin in-country. But those are not ours.

Unknown Analyst

The situation on Heidelberg is a little bit confusing from the outside. I mean, you guys continue to say that it's been within guidance while the partners seem to be disappointed with what is happening. Could you say a little bit more just to help us understand?

Ernest A. Leyendecker
Former Executive Vice President of Exploration

Certainly. So Heidelberg, yes, we do believe it's within our guidance. Of course, we don't break out individual wells or fields, as all of you are keenly aware of, I'm certain. But on an annualized basis, it is still within guidance. So we have 3 wells to date. They're producing about 15,000 barrels a day or so. They all obviously have variable production rates and are being produced variable drawdowns and chokes, et cetera. So not every well is the exact same rate. So a couple of the wells that we have there, we have placed in a structural position different from a third well. And so we have variable production rates from them, and we expect them. The other thing is we continue to manage the drawdown on all of the wells and ramp up production as we continue to monitor the performance of the depletion of the reservoirs. So it's -- for us, it's just routine drilling reservoir surveillance, and every well is different. So as we speak, we're about to spud yet the fourth well at Heidelberg at yet again, different structural location. We did encounter more structural complexities than we initially thought, and that's always the case. You always -- when you put wells, you learn more information about stratigraphy, reservoir rock and fluid properties.

But we don't see it anomalous and certainly within our overall volumes and annual volume guidance. It isn't as material as it is to some of the partners who -- it is a material event, perhaps, for them, and they may see things differently. They may have forecasted things differently than we did. But as the operator, we're managing the wells prudently, and we're ramping the field up carefully because there are a lot of things that can happen if you open up a well and gut it with a really high drawdown. And we don't want that to happen. We've learned a lot of lessons in the Gulf of Mexico over many, many years. And it's just a prudent approach to try and managing the reservoir performances of the wells.

Unknown Analyst

Can you speak to where there might be the most room for incremental cost pullout out of offshore projects right now? And also just maybe speak to where you see the Gulf of Mexico going as far as exploration going.

Ernest A. Leyendecker
Former Executive Vice President of Exploration

So incremental cost pullout, I'll use a baseball analogy. The offshore world probably lag the onshore world in their reactive time to improving the cost structure a little bit. We're probably in about the sixth or seventh inning or so. We've seen some cost reductions in a range of 15% to 30% in various services offshore. Obviously, the rig fleet that is under long-term contract for us and our industry partners is at pre-2014 rig rates. And that market rate has changed because of the rig utilization. So going forward, as those rigs roll off, there is scope, obviously, for hiring rigs at a significantly reduced day rate. And then coupled with the service side, significantly reduced spread rate. So going forward, I think we will see much different well costs and cost structures for opportunities going forward. The second part of your question, I believe, was about Gulf of Mexico exploration. Well, I've worked with the Gulf of Mexico for a long time, and I like to talk about it in the context of being the basin that keeps on giving. There's a few basins around the world that are like that, including the Permian. But in the Gulf, in particular, I believe the Gulf has competitive advantages that are unique to the Gulf. It has a geologic advantage that is remarkable because it has a very rich petroleum system that's very active with lots of sediment input, lots of source rock, lots of salt tectonics that created lots of trapping mechanisms and a lot of well control. So it has a remarkable geologic advantage. It also has a remarkable commercial advantage in that it's a relatively stable fiscal environment. It produces high-margin barrels. It's typically a very, very oily basin, which is why we like it a lot. It has some competitive advantages over a lot of places as well. It's got very mature infrastructure with the pipelines and access to markets that is very different from many, many offshore basins around the world. So the Gulf is a, in my view, one of the most opportunistic places. And you see us, in particular, going forward looking at it in the context of continuing to leverage our hub-and-spoke technology, where we have near infrastructure opportunities, drilling good prospects near good infrastructure, and we have a list of those, really, we continue to work on in and around our fields: Lucius, K2, Caesar/Tonga. So that's where we're focusing a lot of our efforts because we can generate greater than 30% rate of returns. We've already spent the capital on the infrastructures, so it's really a function of getting well tied back into that.

Unknown Analyst

Just had a follow up to the Gulf of Mexico question. In your guidance, I think, you have overall production in the Gulf of Mexico trending down this year versus last year, but liquids production trending up. So I just want to make sure I understand. Is that just legacy gas production sort of declining this year and then the follow up to that is...

Ernest A. Leyendecker
Former Executive Vice President of Exploration

Yes, good question. So really, Independence Hub was our big gas field. It's really been declining quite steadily, and it's being displaced effectively by a full year production from the Lucius field as well as the ramp up of the Heidelberg field to 2016. So we have a full year of Lucius now. And that field continues to produce in an outstanding manner. Just gets better and better [indiscernible] as we see it perform.

Unknown Analyst

You continue to see your liquids production growing in the -- for you guys into '17 and '18?

Ernest A. Leyendecker
Former Executive Vice President of Exploration

We do through the balance of the year and into '17. I can't recall exactly what we've guided to yet on 2017 and beyond. But that'll be a function, obviously, of plateau production performance at the new fields and the new wells. So we continue to drill and complete in and around Caesar/Tonga, K2 and Heidelberg and Lucius.

Unknown Analyst

In terms of the CapEx spend on your larger projects that might not be productive this year, when do you foresee some of these project spends coming online? Is it '18, '19 in terms of turning into productive capital?

Ernest A. Leyendecker
Former Executive Vice President of Exploration

Well, some of that is going to start feathering in into late 2016 and '17 when we think about the tiebacks from the Gulf of Mexico. The other major projects, obviously TEN, we're nearing the end and have a lot of that capital behind us. So third quarter of 2016, we start to see that come online and ultimately ramp up into 2017. Beyond that, major capital projects are, at the moment, idled because of the current price environment. We're taking a very measured approach to continue capital investment in those mid-cycle and megaprojects. Although we continue to look at the long view and realize and recognize that those major projects, those organic projects, continue to give us optionality and option value. The unique thing about those major capital projects is that it really offsets a much higher base decline rate from the unconventionals. So one of the differentiating parts of Anadarko's asset portfolio is that we have a blend of unconventional and conventional. And the conventional is typically defined by higher-margin oil opportunities internationally in the Gulf of Mexico. So to answer your question, kind of that's the landscape of the major capital projects.

Unknown Analyst

So basically, beyond this year, there's -- your capital spend is going to be well focused on productive -- meaning production that comes online?

Ernest A. Leyendecker
Former Executive Vice President of Exploration

Sure.

Unknown Executive

I mean, we're still going to have the longer-day cycle in terms of exploration so far as the -- I think in Ernie's point, in terms of already sanctioned megaprojects, those over projects after TEN, which comes online this year, we don't have anything else sanctioned in the queue. Now Côte d'Ivoire, if successful, could be the next one, but we don't have anything else in terms of dedicated capital with the possible exception of the Delaware Basin where we're spending things and we classify more as mid-cycle because of the appraisal requirements in the delineation that's being done there.

Robert S Morris
Citigroup Inc, Research Division

Ernie, turning over to Mozambique. How confident are you that you'll reach FID for that this year? And what are sort of the boxes you need to check to get there? Is it just things like reaching agreements with the government on a whole host of things, from employing local people, to building roads, to building schools and just getting through a laundry list of items to get to the FID to make sure this project moves forward and the government can't stop it or slow it down at any point?

Ernest A. Leyendecker

Former Executive Vice President of Exploration

So thanks for the question, Bob. The pace of activity is really going to be dictated by the Mozambique government. And the boxes that we still need to check, in that vernacular, really are continuing to secure a legal and contractual framework to enable us to go ahead with all of the engineering procurement, construction and installation parts of the major project. The second major box we need to check really is to convert the Heads of Agreements for LNG into Sales and Purchase Agreements. And finally, the third major box we really need to complete is financing. So really, those are the remaining activities. We'll see how fast the government is willing to move. We're able to maintain the option value on that for less than $100 million of capital in our program this year, so we're not going to sanction it till we're confident we have all those things done, and it's an economic project.

Robert S Morris
Citigroup Inc, Research Division

You said the third thing was financing. Is that the third?

Ernest A. Leyendecker
Former Executive Vice President of Exploration

That's correct.

Robert S Morris
Citigroup Inc, Research Division

Okay. So I guess, confidence in getting that done and getting FID this year? High? Low? 50-50?

Ernest A. Leyendecker
Former Executive Vice President of Exploration

Difficult to gauge. Really, it's -- I think the Mozambique government is motivated, given some recent pressures on them. But it's a new world for them. It's going to be a game changer for that country. So it's hard to really handicap whether we can get there this year or not. We're -- we'll see.

Robert S Morris
Citigroup Inc, Research Division

But the sales contracts for the gas, you have to get the FID and all that settled before you can actually turn the Heads of Agreement into sales contracts, correct?

Ernest A. Leyendecker
Former Executive Vice President of Exploration

We need to get all 3 of those things done, really, to continue to move forward.

Unknown Analyst

What is your long-term strategy for debt reduction? Or do you plan on deleveraging naturally through EBITDA once prices recover?

Ernest A. Leyendecker
Former Executive Vice President of Exploration

So long-term strategy for debt reduction in the balance sheet, we've taken care a lot of the short term things. We will continue to try and build cash through the year through multiple levers. One that I've talked about early was the asset monetizations. We talked about the 2017 maturities that we'll probably look to refinance or do something with the monetizations or our liquidity. Long term, I think we're pretty comfortable where we are at this point in time, and I really can't give you any more color on the rest of the debt at this point in time.

Unknown Analyst

Can you just run through, in terms of the onshore allocation of capital, what sort of price -- I think you're sitting with around 230 DUCs. What sort of price do you anticipate before you'll start ramping up activity in that area? And then, I guess more holistically, how do you internally now think about the allocation of capital to onshore versus offshore -- sorry, domestic versus international?

Ernest A. Leyendecker
Former Executive Vice President of Exploration

So we reduced our maintenance capital onshore in our short-cycle investments by, what, about $900 million year-over-year. And as we think about the forward curve and commodity prices, we're not in a hurry to go back to work and put a bunch of rigs back to work. The 2 basins, of course, that we really like, that are part of the crown jewels of Anadarko's asset portfolio are the DJ Basin in Wattenberg and the Delaware Basin. I think we've talked about the breakeven prices for those 2 assets for new wells being $35 and $30 for the DJ -- I'm sorry, for the Delaware, and then $30 and $25 for new wells drilled and completions, if I got that right. So we're -- we may reallocate capital within the existing capital plan for 2016, but we're not going to continue -- we're not going to add additional capital for those assets. We just don't think we're ready. The $50 mark is not something that we think is a triggering event for us. We really believe we need to see sustained prices for a longer period of time to feel confident that we're going to generate reasonable returns for those short-cycle investments. Putting rigs back to work is really just going to compound the problem and the volatility that we see going forward. We are optimistic that the market will be balanced in the second half of the year. But in our view, it's still going to be a very bumpy ride. There's just going to a lot of volatility between now and then, and it doesn't really cause us to change our capital plans at all and shift dollars, large amount of dollars from international offshore back over to the onshore. We'll move dollars around in and around the U.S. onshore, and we'll continue to maintain our acreage position in the Delaware Basin and grow our midstream position in the Delaware Basin. We're only running about half a dozen rigs or so in total, and those are primarily in the Delaware Basin today.

Robert S Morris
Citigroup Inc, Research Division

But on the DUCs, do you see -- if you do get a more sustained price, is that your trigger? Is that the acceleration of completion on the existing DUCs? Or do you see -- you have to sustain the drilling process on a number of DUCs in the inventory. Or do you see your activity accelerating through completion?

Ernest A. Leyendecker
Former Executive Vice President of Exploration

I don't see activity accelerating, but I'd see us using the intentionally drilled, uncompleted wells as a lever for flexibility.

Unknown Analyst

Sorry, and on the decision on going forward in a $50 to $60 oil price environment, how are you going to decide to allocate that capital for longer term? I don't mean on projects you have now. I mean in terms of going forward, how do you see yourselves structurally?

Ernest A. Leyendecker
Former Executive Vice President of Exploration

For the longer term, we'll -- we have a very comprehensive planning model really and as we think about devolving over the course of this particular cycle, it'll change, honestly, for 2017 and beyond. Our tactical plans, really, like many in the industry, are to survive this particular period, obviously. We're fortunate and blessed to have a diversified portfolio that allows us to do that. But we'll see what the future holds in terms of reallocation of capital. We won't put money back in rigs back to work if it doesn't make any sense, because we're not generating the returns that we need and we're just growing production. Our focus is really on preserving and enhancing value for the future. And we don't see a reason to continue to grow production for the sake of growth at this point in time if there's no returns.

Robert S Morris
Citigroup Inc, Research Division

And sort of in that regard, Ernie, every company we've seen to reported in the last 2 weeks, came in costs lot lower than when they guided to or anticipated. And yourselves, to the extent that while you're keeping your budget the same, you're now going to run 6 instead of 4 rigs in the Delaware with the cost savings you've realized. Is there a lot more? It seems like every quarter, we think we've hit the limit and companies continue to reduce cost and find ways to improve efficiencies. How much more room do we have to run on that? Or is that -- will it continue to be every quarter, continued improvement?

Ernest A. Leyendecker
Former Executive Vice President of Exploration

I think there's probably a little bit more, Bob. I'm not sure how much more there is. I know it probably feels to all of us in the room that we might have bottomed out on the cycle of commodity prices. And as we continue to see upward pressure on oil prices, I think you'll see some return pressure on cost and services. But it will lag. Historically, as I think back across the cycle of my career, it's not an instantaneous thing. I mean, the service side has retired a lot of iron and idled it, and people. So it'll take a while to catch up, is my personal view.

Unknown Analyst

Can I go back to the strategy on the DJ and Delaware because it's slightly different from what I've heard from other people. Or maybe I just don't hear it often at least. I hear others say if we get $50 hedged, grow. And you'll say, "I need to see sustainably the hedging prices, not the price I want, to drive my production." Could you just elaborate? Is it because these don't make appropriate returns at $50 forward? Or is it because you -- this belief about value, and it's better to wait 12 months and get $60 oil. I'm just trying -- it's different from what I've heard from other people. I mean, and I'm interested in -- you must have seen in your share price reaction to this strategy and others' share price reaction to their strategy of hedging and growth.

Ernest A. Leyendecker
Former Executive Vice President of Exploration

So we don't hedge for project economics. We hedge to protect our capital program in our -- on our cash flow. So it is, we look for value. I mean, you hit the nail on the head. We think about our asset portfolio. We're looking at the value proposition there, not just cycling cash in a low-price- environment. So -- and we're, as I've said, we're fortunate to have a diversified choice of assets with which to invest in. And we believe, at the moment, that the offshore Gulf of Mexico tiebacks to generate very robust returns. So we're not ready to go put a bunch of rigs back to work at the current price environment in the Delaware or the DJ and just cycle cash. We would prefer to preserve that value for a future date and, yes, a higher commodity price environment. We'll maintain our -- the assets, obviously, and maintain production and maintain the leases and maintain the facilities. But as I said earlier, we'll take the intentional drilled and completed wells and use those for flexibility where we can. Given the Gulf or the international portfolio that allows us to exit the year in effectively flat oil volumes, there's no need for us to reallocate and add more rigs and allocate more capital to the Delaware, in the Permian or the DJ at this point in time.

Robert S Morris
Citigroup Inc, Research Division

Ernie, you've been pretty disciplined on the onshore U.S. You got your 2 big plays as you mentioned, the DJ Basin and the Delaware. The Delaware is something that you sort of entered into just a few years ago. There have been several companies at the conference talk about new plays and doing exploration, acquiring acreage and potential new plays onshore in the U.S. Are you guys also looking -- or do you see other plays that you'd like to enter into to add to the Delaware and the DJ?

Ernest A. Leyendecker
Former Executive Vice President of Exploration

We don't ordinarily talk about what new plays we're looking at. We lose our competitive advantage. But I would remind you that we recently increased the total resources in our Delaware position to 2 billion barrels of resources. So we have about 10 different stack intervals out there in the Delaware Basin, that we think there's lots of vertical opportunity within the existing position. So there's lots of running room there. Having said that, as you all know, we're very active managers of our portfolio. We will continue to optimize our positions and where we think it's right, sell or buy. But we don't have any -- we're not telling you what we're going to buy or sell today. We just like the Permian because it's another basin that keeps on giving, and our position in the Delaware, we think is a premier position.

Robert S Morris
Citigroup Inc, Research Division

Yes, I don't expect you to tell us what you're buying. But are there other plays? So is there something else out there that you're excited about, that you're acquiring acreage on that you think is something you could talk about in the future?

Ernest A. Leyendecker
Former Executive Vice President of Exploration

Not at this point in time, Bob. We're not prepared to talk about any of those.

Robert S Morris
Citigroup Inc, Research Division

Okay. So you're not out buying acreage.

Ernest A. Leyendecker
Former Executive Vice President of Exploration

No comment.

Robert S Morris
Citigroup Inc, Research Division

Okay. I'm sorry, I didn't mean to push.

Unknown Analyst

A question on the midstream side of the equation. You've extracted about $13 billion, I guess, out of WES and WGP over the last several years. Can you just comment how you look at that vehicle as a -- do you look at it as funding vehicle? Do you look at it as sort of a partner as you grow the business? I'm just trying to understand how you look at that entity. And there's been -- there were some comments in the press that you used the MLP to fund Mozambique. In some ways, you're performing -- liquidate some portion of it to finance Mozambique. So I'm just trying to understand how you're looking at the vehicle.

Ernest A. Leyendecker
Former Executive Vice President of Exploration

So great question. Thank you very much, and you're spot on. We do look at it as a lever for potential funding. As we have historically, you've seen us issue secondary -- make secondary offerings and generate a little bit of liquidity. But we also look at it in the context of being a partner, a facilitative partner for midstream and allows us to control our takeaway with WES. So we will continue to look at the options in and around WES as a vehicle for liquidity. We're not saying we're going to do anything today, but that's how we look at it, exactly as you described it. It's a lever for us.

Unknown Analyst

And what's -- I mean, what's the real backlog for WES today, I mean, given your slowdown in the capital budget. I mean, is there still a significant backlog for WES or West GP in terms of growth? Or does that slow down eventually?

Ernest A. Leyendecker

Former Executive Vice President of Exploration

Tough question there. There are still assets that we believe would make sense materially to fit into the West portfolio. We're not talking about them today. We'll see what the future holds for WES.

Unknown Executive

Yes, I could add to that a little bit if you like, Ernie. Whereas -- when WES was originally created, it was primarily a drop-down story, because you had substantial EBITDA at the Anadarko level that can be dropped down to fund the growth and distributions of Western Gas. And today, you still probably have the neighborhood of about $200 million of EBITDA sitting at the Anadarko level that's eligible for drop-down. But Western Gas has matured so that is now -- probably more of its growth is actually coming from organic projects. That's building out new assets for Anadarko as our partner in the Delaware Basin, which is an area that has, as Ernie mentioned, has fantastic resource potential but is starved for infrastructure. And so if you actually look at Western Gas over last couple of years, they have spent more on midstream capital and development than Anadarko has as part of that evolution, and they've been actively out building out third-party business. So they certainly see particularly in the Delaware, they see quite a bit of room for growth and expansion through that side. So it continues to be, as Ernie says, not only a partner for us in building out our competitive advantages for various spaces, but also a source of funds, i.e., through drop downs like we did this year or in [indiscernible] MLP markets when we'll go back to selling more of our ownership out, and so we still control about 84% of WGP.

Unknown Analyst

Could you speak a little bit about the bid for asset sales right now? I know Conoco said in their last conference call that it's gotten softer. Other E&P companies are saying that assets are getting bid up, discounting $20 higher prices, and it seems like there's a very big disparity between where asset prices are now. Actually depends on whether or not somebody's a seller of assets or not, but just maybe speak to that.

Ernest A. Leyendecker
Former Executive Vice President of Exploration

Well, I think there's always a healthy spread between bid and ask. And particularly right now, people -- the bidders want premium and top price and -- sorry, the people asking or selling their properties are looking for 2014 type of valuations. But the bidders are not willing to pay that right now. So we still see it as a pretty healthy market, to be honest with you, and there are regionally -- regional differences and competitiveness for particular assets. Obviously, the Delaware and the Permian is still fairly attractive plays, attracting a lot of capital. And there are other places that are a little bit softer than that at the moment. So still a healthy bid-ask spread. We're getting a lot, as I said earlier, we're getting -- we're still getting a lot of inbound traffic, but it's always a negotiation in the end. The value is in the eye of the beholder.

Robert S Morris
Citigroup Inc, Research Division

All right. Well, we're out of time. So Ernie, thank you very much for presenting this morning, asking all the -- answering all the questions. And everyone, thank you.

Ernest A. Leyendecker
Former Executive Vice President of Exploration
Thank you, Bob. Appreciate it.

Exhibit 107

Corrected Transcript

24-May-2016

Anadarko Petroleum Corp. (APC)

UBS Global Oil & Gas Conference

Exhibit
547

CORPORATE PARTICIPANTS

Robert G. Gwin
Executive Vice President-Finance & Chief Financial Officer

Shandell Szabo
Director-Investor Relations, Anadarko Petroleum Corp.

MANAGEMENT DISCUSSION SECTION

Robert G. Gwin
Executive Vice President-Finance & Chief Financial Officer

Yeah.

Unverified Participant

Okay. All right. We're going to get started. Our next presentation is Anadarko Petroleum. We've got a number of people from the IR team. I'm sure everybody knows John Colglazier, Brian and Shandell, who's recently joined the team. But to give the presentation today, we've got CFO, Bob Gwin.

So with that, I'll hand it off to Bob.

Robert G. Gwin
Executive Vice President-Finance & Chief Financial Officer

[ph] Bill (00:25), thanks and thanks for having us again. I love coming to Austin and it's one of the better and more enjoyable locations for us to come to every year. So we appreciate you continuing to invite us and have us here.

I want to talk for a moment about where we are this year. This slide, many of you may have seen for the first time on March 1st, we had our investor call and laid out our plan for the year. We say it's successfully navigating in a volatile environment and hopefully this environment has improved a little since March. Certainly, we've seen some encouraging signs on the commodity front and we, along with everyone else, are able to look a little more excited at the balance of the year and what the rest of the year could mean for us as we look at how we want to allocate that capital that's shown here at the bottom the page.

Back in March, when we laid this out, we wanted to focus a lot of our spending on the short cycle. For us, that means primarily in the DJ Basin and on a material number of tiebacks in the Gulf of Mexico that I'm going to talk about in more detail shortly, the fact that we're bringing TEN on later this year.

We also try to always look at the intermediate cycle and the longer cycle spend. We believe that continuing to focus solely on the short cycle creates a bit of a treadmill and creates less visibility on where future growth is going to come from. And so year in and year out, we'll allocate varying amounts to the mid- and long-cycle projects.

If you look to the long cycle first, that's primarily exploration projects, but also some of the longer cycle development projects. Shenandoah, which we're going to talk about a little bit today; Colombia, where we have had some very encouraging drilling results; Mozambique, which we've talked about quite a bit in the past.

And then in at mid-cycle, we treat the Delaware Basin as a mid-cycle for one key reason. Certainly, we're seeing some of our investment in shorter cash cycle, but a lot of what we're doing there is moving toward a pad drilling environment after we get our infrastructure in place and are able to really drive down our well economics. And so, we think of this more as kind of a bit more of a science stage today where we're focusing on delineating our acreage position, building the infrastructure and positioning for the future.

And as the year goes on and we see some strengthening in the commodity cycle, which, of course, we hope to see, then although we don't expect to increase the capital budget during the course of the year, we might move some of this capital around to take advantage of the improving return dynamics in the short term.

So in 2016, there's a couple of things to talk about. You can see the numbers around our capital spend and our expectations on sales. We expect sales to come off a little during the year, that's all gas. Importantly, because of our diversified portfolio and the focus on some of the mega projects that have represented kind of that mid- and long-cycle spending in the past, those projects come on this year with Heidelberg earlier this year and the TEN development coming on later next year, helps us to keep those oil volumes flat.

Even though we've taken down capital 50% year-over-year, we think that that shows the resiliency of the portfolio, the low maintenance capital I'll talk about in a little bit. And we're pretty proud of that profile. Being able to keep oil flat year-over-year in this environment with really strong return dynamics we're pretty proud of.

One of the key things we're talking about doing this year and some of these slides will cover is a focus on the balance sheet, a focus on addressing some near-term maturities. We've talked in the past about reducing our net debt position and prospectively our gross debt position and we expect to do that largely through monetization. We're going to moderately outspend our early year expectations on discretionary cash flow, but spend well inside of our cash inflows, if you include the discretionary cash flow plus the cash from monetizations.

Now, we've talked at the time we laid this plan out in early March about $1.3 billion of monetizations that are now closed. And on our quarterly earnings call a couple of weeks back, we talked about another $700 million that we've reached agreement on and are working toward – moving toward closure. That gives us about $2 billion in the aggregate.

And for those of you following at home, we talked earlier this year about $2 billion to $3 billion in the aggregate of asset monetizations that we felt was appropriate to be able to not only supplement the funding of our program this year, but, as I mentioned earlier, to bring down the net debt and to use proceeds from asset sales to reduce the gross debt number. And so that's what we mean by they are underway.

Now, I'll point out that beyond that first $2 billion, we've got a number of projects that we continue to work on. And that $3 billion total number or the marginal billion that we're working on is a risk number. We've got a number of assets we've looked at that we don't think we'll receive funding relative to our very attractive opportunities in the DJ Basin and then the Delaware Basin, Wolfcamp, as well as these tieback opportunities in the Gulf of Mexico.

We think that will be the place we go to put our future capital primarily, and accordingly, some of these assets that have really good solid return economics at strip, primarily gas assets, we think are probably better in someone

else's portfolio. And we are probably better monetizing them, redeploying those proceeds into first-producing debt and then into growing the company as we go forward.

I mentioned our maintenance capital; it's shown here on the graph in the gray at the bottom. That number has continued to come down over the last few years. A lot of that is because we've been bringing on these very attractive mega projects like Lucius coming on last year and as I mentioned, the other projects that will come on this year.

This is a snapshot at a point in time to show you where we spent the capital and the areas we spent it. And as you see last year and this year, we haven't focused any capital on growth. We focused on maintenance capital and on positioning the rest of the portfolio for growth in the future when the economics are sharply improved with an improved commodity price environment that we would expect.

We mentioned on here also that we will leverage what we call the IDUC inventory. Many of you are familiar with the DUC term, that's emerged a lot over the last of couple of years. IDUCs, the I stands for intentionally deferred, and those are the wells that we – after we drill, we wait to complete as opposed to the ones that are within our normal profile where we're always cycling crudes in and out of those assets and they're getting completed really concurrently or just after the drilling process.

We have about 230 of those in inventory when we entered the year and we didn't use up any of them, didn't go through any of them in the first quarter. We expect we'll go through a few. Our base case plan that I laid out on the prior slide includes working through a little bit of that inventory. But importantly, we look at these DUCs or these IDUCs, just like we do the rest of our portfolio. They need to be considered on a full cycle return on capital basis.

And so, even though the marginal economics of completing these today look attractive, and you would go ahead even at strip and complete these. We'd like to see moderately stronger commodity prices before we start moving into that inventory and eating through it because we're focused on ensuring. So we can't just ignore that sunk capital in the asset acquisition costs and the drilling expenses that have already occurred.

In general, this gives us a much flatter decline curve than many of the companies in the industry. And that diversified portfolio, the mega projects, the ongoing oil developments in West Africa and Algeria supplementing that give us a profile that puts less pressure on our capital spending, gives us more flexibility for the future, and lets us ramp down capital sharply and maintain oil production.

The core part of our strategy for at least the last 10 years, I guess probably goes back almost 13 years, is the concept of financial discipline. And for us, what that has meant over time is spending within cash flows. And it doesn't mean spending within cash flows every year; it means in good times you're going to spend less than your cash flow and in bad times, you're probably going to spend a little more than your cash flow, your discretionary cash flow.

And importantly, because we've looked at monetizations as a core part of our strategy for at least the last nine years since we started selling assets in 2007 coming out the acquisitions of Kerr-McGee and Western Gas Resources, we put this chart together to show really kind of what that's resulted in. And what it's resulted in is that we've generated an adjusted free cash flow, so that's this free cash flow plus proceeds from monetizations of approximately $14 billion over the course of just the last – just over six years.

The material amount of cash-generating capability – and over this period of time, we don't have it on here, but if you look our production profile and our reserve growth and the other core metrics, especially on a debt adjusted share basis, the way that we have traditionally and will continue to run our business, we think this is a track record

that speaks for itself and it's one that we think gives us a bit of an advantage in the current environment when everybody wants to get in the market and sell assets. Truly a core part of what we do year in and year out, it's a core competency, and I think it's why we've been successful year-to-date, and why we feel comfortable with successfully executing the targets that we've laid out there through the rest of the year.

Now, some of the things we've been doing behind the scenes that help us to generate more cash and more cash available to address either debt reduction or reinvestment is things like cutting the dividend – earlier this year, we cut the dividend by $450 million a year – or cutting expenses. The last year, we were very good at cutting our expense profile, what I'd like I think of as kind of close to the wellhead, the changes some of which were cyclical, some of which were, we think, more sustainable and permanent. We were very successful on taking a lot of cost out of the system last year. But this year, we addressed a lot of costs that are a little further away from the wellhead.

Regretfully, we had to approach a material staff reduction earlier in the year where we had to let go about 17% of our staff. We also started over some zero-based budgeting, bottoms up, and we have about $350 million of annualized costs we've taken out of the system on that basis.

So along with the dividend cuts, we feel like we've improved the cash profile by about $800 million a year, regardless of what happens on the operations front. And although that's big for a company even our size, we think about it almost on a multi-year basis. Those tend to be not necessarily permanent, but if the environment stays weak, those are expenses that we think you're going to benefit from over maybe say a three-year period maybe $2.5 billion, very significant as you kind of realize what could be a lower long-term commodity price environment, not lower than where we are today, but certainly lower than the very high commodity prices in the past.

So we feel good about the cost structure, good about the ability to monetize assets. We think that from a financial standpoint, all the arrows are pointed in the right direction. There was an issue earlier this year where the market was quite concerned about nearer-term maturities. If you look at the first two years in this graph, they're meant to indicate our debt maturities in 2016 and 2017 prior to the work that we did earlier this year.

We were able to execute a $3 billion bond offering. We went to the market with a smaller offering, had over $20 billion of bids, enabled us to upsize the deal and decided to upsize it to $3 billion. We got asked by many people, why didn't we just upsize it to $3.75 billion and eliminate those first two towers in their entirety? And quite frankly, it's because we mean what we say about reducing gross debt. And had we refinanced those towers in their entirety, it would have left us with less flexibility around where the debt reduction was coming. And so we've left – that's the solid blue here on the 2017 chart – we've left $750 million that we said in the press release just recently several weeks ago that we expect to repay out of cash, and that cash will largely come from those proceeds from asset sales that we're working on.

So it gives us a lot of flexibility, and even though that $3 billion listed on this chart that we had on hand at the end of first quarter, when we called the debt, the 2016s, and we tendered for the 2017s successfully, that used up the $3 billion that we had done in the debt proceed – from debt proceeds. But we've also brought in a material tax refund and other cash during the year. So we maintain a pretty robust cash position as well as $5 billion of working capital facilities, revolving credit facilities.

We feel pretty comfortable this liquidity position gives us a lot of flexibility to manage the business through the course of the year. And of course, by taking care of the near-term maturities, our maturities now are really not a concern for the next several years and hopefully, those that were concerned about our ability to address these near-term liquidity needs or nearer-term needs have now been put to bed.

So what I want to spend a few minutes talking about on the next four slides is the Gulf of Mexico position. We often will talk about a lot of assets in the portfolio and show you our maps around North America and other places in the world, and we are going to do that today. Those are in your appendix you can refer to. Many of you that know our story are familiar with those issues or you have one-on-one schedule with John and his team, and we can certainly talk about the other assets. We're incredibly excited about the DJ Basin, for instance, incredibly excited about the improvements in the Delaware where we recently, on our last earnings call for instance, brought up our estimations of the size of our opportunity there, the 2 billion barrels for instance.

Those are all great and they're very interesting. But one of the things that we get questions on sometimes is the Gulf of Mexico. One of the reasons that we get those questions is because a lot of companies, a lot of what I call formerly peers of ours in the Gulf of Mexico have made decision to exit the Gulf of Mexico and focus their attentions entirely on the shorter-cycle, higher-decline in U.S. onshore business.

And with that addressing other's decisions, I wanted to talk about what we've done and why. And the reason we've chosen to stay in the Gulf of Mexico and to continuing to invest in the Gulf of Mexico is because we're good at it. We've made shareholders a lot of money over the course of the last several years in the Gulf of Mexico through our core skills. And those core skills are in exploration, where we have over a 60% success rate in the Gulf of Mexico. We're excellent in project management. We are top quartile year-in and year-out over the last decade on bringing projects in on time and on budget. We're creative in terms of our Kerr-McGee legacy is creative in bringing on for instance the first spar design technologies; we've reutilized spar design technology over and over in some of these deepwater development. At Lucius for instance, as many might remember, we had an 80,000 barrel a day spar that we decided, when we had the Heidelberg discovery, that we could replicate that Heidelberg spar and – or that Lucius spar and use it at Heidelberg. Saved us hundreds of millions of dollars and accelerated our development timeline by 18 months. That adds a lot of value when you're talking about the type of capital that is traditionally associated with these kinds of facilities.

And quite frankly, we think we've been pretty good at being smart about the way we allocate capital and the way we monetize assets in the Gulf of Mexico. We put on here that we've developed the best and – or we'll develop the best and divest the rest. And we've done that to a significant degree. We've sold over $4 million of properties. We've had over $2 billion of capital that otherwise would've been our capital carried in the Gulf of Mexico. The most significant of those are Lucius and Heidelberg platforms where we had our development capital carried by partners that came in and purchased a portion of our prior working interest.

We also do a fair amount of farming down of our exploration prospects, so that we drill many prospects either free or for a very low cost. So we're able to change the economic profile that is already intrinsically strong by utilizing some financial structure into materially enhanced rates of return and to reduce capital deployed. And so we've taken about $16 billion of cash value out of the Gulf of Mexico over this period of time.

But what we've been left with is still a massive resource opportunity, 800 – north of 800 million barrels of discovered net resources, which we're moving toward value realization either through development or potentially in some cases ultimately a sale. And we still have a material exploration footprint in the Gulf of Mexico with over 1.6 million acres.

So this slide, I want to take a minute and make sure you follow what we're showing you here. We've got a lot of questions on – and we've talked about our tieback opportunities in the Gulf. And I mentioned it earlier today that we're really excited about this tieback opportunity. So I hope this slide starts to show you why, because the questions we've got made us realized that people didn't necessarily understand what was so compelling about these opportunities.

First of all, there's over 30 of them, and we'll probably get to five to seven of them this year. But look at the economics in the box on the left. These are 20 million to 25 million barrel opportunities, sizable opportunities, probably cost us $200 million or so for DCNE. That gives us roughly a $12 per barrel or less development cost. This is comparable to what you'd see onshore in our pad drilling opportunities. So this competes for capital on a heads-up basis, competes for capital very effectively against onshore opportunities. Cycle times are short. Usually if you're talking about a Gulf of Mexico project, you're talking about a long kind of a mega project, multi-year investment, and wait for your cash flow to come back to you. But instead, in these opportunities, cash comes back to you in roughly about a six-month period where you drill the well and are working on a tieback solution.

One of the ways we do this is we have a lot of owned infrastructure. We've got eight facilities in the Gulf of Mexico and some of our more recent ones are in some of the best neighborhoods available and we'll show you some maps and talk about those assets a little bit. And you look at that production profile on the bottom left. They come on at 10, 11 – this is – some will be bigger, certainly, like at Lucius, but the average one come on at somewhere in the neighborhood of 10,000 barrels a day or 11,000 barrels a day, stay flat for a period of time before they go on decline, very, very different than the decline profile you're going to see in an unconventional play onshore.

And you overlay all these economics, net production profile, and you begin to see that these have tremendous economics. What you might not see is just how good the economics are. We talked earlier this year about these opportunities being better than a 30% rate of return. That was in a much lower commodity price environment when we were making that statement. What we can tell you today is that at $60 oil – which hopefully is on the horizon for us here – with $60 oil, these opportunities have better than a 70% rate of return, one of the best opportunities in North America. It happens to be offshore where a lot of people have left, but it happens to be a place where we think that we can apply our expertise and our demonstrated success and drive a lot of value going forward. And of course, because if we're going to get to five or seven of these this year and there's 30-plus opportunities, this isn't a one-trick pony; this is a few years of running room.

Talking specifically on this slide about a few of those opportunities, it's places like Caesar/Tonga, where we have opportunities, we look at drilling two this year, and then move into Phase 2 we work additionally on the facilities and tieback into our 100% owned constitution spar. This is the type of thing – when we talk about a tieback opportunity, it's run rate to what we do, it's traditional work that we do. But when you start to look at the relative economics, because your infrastructure costs have already earned a the rate of return, and you can look at your point forward economics around these tiebacks, they get very, very powerful. And you can see the impact, just for instance looking at the Caesar/Tonga slide. As you get past this year, those wells start to come on. You layer in a couple of them, and suddenly they extend that production profile to spar many years into the future – hugely, hugely valuable high-margin cash flows coming back at you, much higher margins per barrel than you realized in the U.S. onshore.

Lucius, I think everybody's largely familiar with. It's been a tremendous success story for a lot of reasons. Our economics are really phenomenal. We were able to drill our exploratory wells with third-party capital. Our development costs were with a significant amount of third-party capital. Our development costs were largely covered by our farm-down to our partner. It has served as a nice regional hub with lots of tieback opportunities. The red there is gas that we bring across the platform from Hadrian South.

We're producing above the 80,000 barrel nameplate capacity today. Obviously, there's some additional drilling of – like Lucius 7 I think is next on the agenda. Phobos is a possibility for a tieback, which is a discovery of ours to the south. And I've got to tell you, I think that this type of a model is one that's underappreciated by the market, and you can see that it has the ability to get financial leverage to Anadarko's equity interest several places and in several different manners. And it's one of these things that we think as a – the place to be for production to come in the area probably has additional upside relative to production handling as well.

Heidelberg's a classic one as well. As I mentioned, we built a twin spar here, didn't design the spar fit-for-purpose for Heidelberg. We designed it just like Lucius-7 for 80,000 barrels a day. Even though that's more capacity than the Heidelberg development itself needed, it saved us money and accelerated our development time line, and it gave us yet another facility with capacity in a good neighborhood to use for future tieback opportunities. We'll ramp up the facility we brought on earlier this year. We'll continue to ramp it up during the course of the year, and then you can start to see in the graph where we think the tieback opportunities are going to help us bring additional volumes across the spar, those tieback opportunities being somewhat our own and somewhat others.

We've got two phase 1 wells, I think, on this map. You can see them in the blue triangles sitting to the north and the south of the three producers that are already online, the three red dots, as we continue to ramp up Heidelberg this year, and then continue to use it as another lever in the Gulf of Mexico for tiebacks.

So the one thing I want to point is the dates at the right side of each of these maps at the bottom, 2022, 2024 – it's not like these things are going to come on and we got to figure out where we replace this production from over the course of the next few years. This is why your maintenance capital number gets to be pretty good. This is how you keep oil production volumes flat, the benefits of a diversified and balanced portfolio.

Now, the woman whose team discovered Lucius, thankfully, is sitting to my right, Shandell Szabo, who is in our exploration group and one of our more successful explorations over the last number of years. Thankfully we're able to pull her out of that role and bring her into John Colglazier's group in IR. And I thought that since she's here with us, she can speak to Shenandoah with a hell of lot better accuracy than I can. This is an opportunity we are incredibly excited about. You see the log and even a financial person can look at the log and say that's pretty good. That's the log from Shenandoah-2. And as we've continued to move forward with Shenandoah drilling Shenandoah-5 now, we've gotten even more excited about the upside and the potential here as we move towards the development. I thought it might be good for Shandell to take a moment, talk to you a little bit about this program, where it's been, kind of where it's going, what we expect in the future, and I guess many of the reasons why we're so excited about it.

Shandell Szabo
Director-Investor Relations, Anadarko Petroleum Corp.

Yeah. No, I appreciate that. I think when you look at Shenandoah, it goes without saying that it is the finest lower tertiary discovery to date in the Gulf of Mexico. And I say that because of the few reasons. When you're looking at this resource potential you look at a couple of things. One, you look at thickness; two, you look at area; and then three, recovery factor. And when you look at this log and you can see that 100-foot scale bar on there, that's a 1,000 feet of sand full of hydrocarbons. So one, it's extremely thick.

Two, when you look at the scale across those blocks and you can see the northern part there, this spans nine miles. Those are three-mile blocks. So you're talking about something that has a lot of area, which is really the biggest driving factor when you talk about size.

And then the last thing is the recovery of this. And so, this particular discovery has Miocene-like properties, which means that the reservoir quality is very good. You're looking at porosities up to 25% here. You're looking at permeabilities in the 100 millidarcy range, some of the individual sand sea 300 millidarcies, 400 millidarcies perm.

And then the last thing you look at is the fluid properties, and it's very light oil out here. So from the overall discovery, it's got everything that you're looking for. We just – as Bob mentioned, we just finished – we're just

about to finish up the five wells, so we can't reveal exactly what's going on there, but what I would say that it looks a whole heck of lot like the log that you're looking at right here. And when you look at where that falls on that cross section, you can see the Number 5 well up there on that cross-section. So you can see that lighter green color. We're going to be able to turn that dark green. So the lighter green on there is the probable and the darker green is the proven. And so we're going to have the ability for that large area over there to go ahead and say, yeah, that's proven. So that's tremendous for us.

So the Number 6 well was very dependent on what we saw on the Number 5 well. And so what we can say is that we're definitely drilling the Number 6 well, and we're out there to hunt for the oil water contact, which is going to give us a whole hack of a lot more comfort around just how big is this. We know it's big, but not only is it big, but it sits on a fantastic basin. When Bob talks about these opportunities in his tiebacks, we also operate Yucatan and Coronado, which sit right in the same basin. And so this is a – we want Shenandoah to be a standalone on its own. Its economics need to support that project. But we do have the opportunity to leverage the infrastructure when we do put it out there.

So we're going to go ahead and spud the Shenandoah-4 well at the – or the 6 well, sorry, in the fourth quarter. The FEED study is already under way, you should take some comfort that we're committed to the development out here. The last two wells that we drilled are keeper wells, which means that when we take this to production, we will be able to produce from those wellbores.

And the other thing that I would note is that we've actually dropped our cost out here by 40% from the beginning to the end. So when we look at the better oil backdrop we've got right now and the fact that we're driving cost down here and we just continue to see great explorations and appraisal success out here, we're going to continue the appraisal work, finish it, we're going to incorporate it into our modeling, and then we're going to move forward with the proper size development out there. But this isn't the only thing we have going on out here, and I think Bob's going to talk to you next about all the other exploration opportunities that we have in the Gulf of Mexico and how we believe that we're going to continue to replicate our success out here and implement our strategy.

Robert G. Gwin
Executive Vice President-Finance & Chief Financial Officer

Thanks, Shandell. I think I'm going to talk about – yeah, there we go. So we wanted to show kind of the size of the prize, if you will. We've got – we put on the slide here about 60 captured opportunities. I mentioned earlier 1.6 million acres. We labeled on here these five red names as APC discoveries. Those are really just kind of our current discoveries that we are appraising. If you were to put on here APC discoveries, you'd have to put them all over this map, look at where our facilities and infrastructure are, and you'd see a lot more red. These are just the ones that we continue to work through the system right now. You can see the appraisal and exploration opportunities are these blue triangles we've named. We've put a few of the prospect names on here.

One of the interesting things you can see is that many of these are located close to existing infrastructure. I didn't mention for instance on tiebacks, we've got tieback opportunities at K-2, we've got the Warrior and Samurai prospects in the area. We've got opportunities to leverage existing infrastructure even through additional exploratory drilling, not just what we think of as tieback opportunities, because there's infrastructure in the area.

Periodically, you are positively surprised on the size of some of these things. They may support their own infrastructure, but it gives us the ability to leverage what we've done with exposing a moderate amount of exploration capital in any given year to create tremendous upside optionality. We think that that positively skewed prospect of a relatively low amount of capital for a relatively sizable future opportunity is a value proposition that's fairly compelling. It's supported, of course, by an exploration program like Gulf of Mexico that has been more than

self-funding. It's generated several times what we've spent there in terms of cash profits if you think back to that $16 billion – or cash proceeds, if you think back to that $16 billion number I've talked about earlier.

So I hope that you realize that as we go forward and we test three, four, five of these opportunities in any given year and we talk about the tieback inventory, a little bit of the perspective that we've given you on these last four slides, helps to cause you to realize why we think this as an area of superb opportunity, the competitive dynamic probably lessens a little as we see people exit the Gulf.

The regulatory environment is a continuing consideration and something that we have to be conscious of, but we think that our experience and our size and our scale helps us to manage that. And hopefully, you'll see why we get really excited about the Gulf of Mexico as a place not just for today, but for the future.

So with that, this is kind of our de facto concluding slide. We continue to focus on value. We continue to focus on rates of return, not really focused on growth, trying to answer the question ourselves that often people answer at what price do you go back to work. That's a multi-dimensional question because, obviously, it depends on the individual assets and the economics associated with that asset.

Despite that, we want to maintain that financial discipline; focus on the asset sales; pay down the debt; not respond to a higher commodity price environment by increasing spending this year, but rather by reallocating our capital based upon the opportunities that a higher commodity price environment might represent; benefit from our diversification; benefit from the fact that we can move capital around between the onshore, the offshore, the international; use our capital allocation skills, which have been a competitive advantage in the past as we go forward. And quite frankly, I think that as commodity prices improve, we're going to be able to leverage this combined and balanced portfolio very effectively and I think that it therefore makes Anadarko a compelling equity opportunity today.

So, with that, I guess end of our prepared comments. If you want to talk about Q&A, [ph] Bill (31:25), at all.

Unverified Participant

Sure.

Robert G. Gwin

Executive Vice President-Finance & Chief Financial Officer

I guess we can do that.

QUESTION AND ANSWER SECTION

Q

So I'd start out with a quick one since we have Shandell up here on – you talked about a $30 breakeven on tiebacks and I know you're still appraising Shenandoah, but do you have a rough idea of how low an oil price would...

Robert G. Gwin
Executive Vice President-Finance & Chief Financial Officer

A

Tiebacks for breakeven, we're on $15 I think before.

Q

Oh, 15%. Sorry.

Robert G. Gwin
Executive Vice President-Finance & Chief Financial Officer

A

Yeah. It's that at 30%, we – earlier this year, when we're talking about $30, we're seeing kind of 30% rates of return available to us.

Q

Okay. All right. So how low an oil price could you move forward with Shenandoah? And then also with the Number 6 well, I guess, that spuds in the fourth quarter. If you find oil-water contact, will that be enough to determine the size and move towards FID, if you have any coming out today. Then finally pref rights, where are the timing on the pref rights for the Marathon sale?

Robert G. Gwin
Executive Vice President-Finance & Chief Financial Officer

A

Timing is very, very near term and we were going to participate there. I think I got a question with someone ask me why we didn't and, in fact, we are participating there. And that's very, very soon.

Maybe if we could go, I'd ask Shandell to address maybe the Shen-6 question and then I'll address your question on development economics.

Shandell Szabo
Director-Investor Relations, Anadarko Petroleum Corp.

A

Yeah. So with the Shen-6 well, we're targeting trying to find the oil-water contact and we're pushing that pretty far down the structure. So we had some confidence that we will see the water contact there. That's going to ultimately give us the true resource size. Without that contact, that's really hard for us to be able to say exactly with the ranges and the fact that we're in that basin, it's going to be really important for us to be able to do that.

So, yeah, I would say that that well – there's the opportunity for one more wellbore if we don't find any oil-water contact. And then we would be forced to drill one more well. But if we do find the oil-water contact, we're going to have a really good feeling for that, that eastern side of the basin.

Robert G. Gwin
Executive Vice President-Finance & Chief Financial Officer

A

Yeah. And so, [ph] Bill (33:19), I mean the reason I asked Shandell to address that, first, is that I can't answer your question on development cost. I can give you some conceptual comments.

Shandell Szabo
Director-Investor Relations, Anadarko Petroleum Corp

A

Yeah.

Robert G. Gwin
Executive Vice President-Finance & Chief Financial Officer

A

But, first, we have to know what it is we're developing. And so, first, we have to understand the reservoir characteristics better than we do today. We said there's some pre-FEED work. There's some work we can do that I think up, is almost kind of the fixed component of the work that we know is going to be kind of consistent whether we move to development knowing what we know today, or we move to development with an opportunity that it's changed with what we learned at Shen-5 and then Shen-6. But as we work the Shen-5 information into our model, it's going to change the scope of the development very clearly and it will change where we go with the development from maybe a design standpoint and certainly a scale standpoint.

And so, it's a question we have avoided answering because we really don't want to get numbers in people's minds until we know what a development plan actually looks like. What we can tell you is that everything we've been doing brings that number down at which you'd be very excited to take FID knowing that the rates of return here would be compelling. And so, that – I'll call it not just that breakeven number, but the number at which you'd really be excited about sanctioning and moving the project forward, continues to come down with success. So Shen-5 is a material de-risking of what we're doing. It's also going to be a significant amount of information to work into our models and the work that our engineers are doing around what that development solution looks like.

The goal here is to do it as efficiently as possible to get the best risk-adjusted rates of return. The more we learn, the more well control we have through the wells that are currently being drilled and the to-be drilled well, the more insight we'll have and the better we can answer the question sooner. But today, we just don't know

What we can tell you is it's – we feel like it's pretty easy to get to breakeven returns. The key is we want to understand what the right solution is to maximize the economic returns for ourselves and our partners, and to consider the fact that is – as Shandell pointed out, there's already known tieback opportunities in the area. So how you size your facility relative to your own production profile in the development of the base field and how you want to consider the economics of the tiebacks all goes into the equation. It's complex, but it's pointed in the right direction in our opinion.

Q

Any questions for the Anadarko team? No?

Unverified Participant

Okay. All right. Now, please join me in thanking Anadarko.

Robert G. Gwin

Executive Vice President-Finance & Chief Financial Officer

Thanks for your attention today. Thanks.

Exhibit 108

ANADARKO PETROLEUM CORPORATION

INVESTOR RELATIONS

JOHN COLGLAZIER
Senior Vice President
832 636 2306

BRIAN KUCK
Director
832 636 7135

JEREMY SMITH
Director
832 636 1544

SHANDELL SZABO
Director
832 636 3977

UBS GLOBAL OIL & GAS CONFERENCE

Bob Gwin, EVP Finance and CFO

May 24, 2016

Cautionary Language

Regarding Forward-Looking Statements and Other Matters

This presentation contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Anadarko believes that its expectations are based on reasonable assumptions. No assurance, however, can be given that such expectations will prove to have been correct. A number of factors could cause actual results to differ materially from the projections, anticipated results, or other expectations expressed in this presentation, including Anadarko's ability to realize its expectations regarding performance in this challenging economic environment and meet financial and operating guidance; timely complete and commercially operate the projects and drilling prospects identified in this presentation; reduce its net debt; consummate the transactions described in this presentation and identify and complete additional transactions; achieve further drilling cost reductions and efficiencies; successfully plan, secure necessary government approvals, enter into long-term sales contracts, finance, build, and operate the necessary infrastructure and LNG park in Mozambique; and achieve production expectations on its mega projects. See "Risk Factors" in the company's 2015 Annual Report on Form 10-K, Quarterly Reports on Form 10-Q and other public filings and press releases. Anadarko undertakes no obligation to publicly update or revise any forward-looking statements.

Please also see our website at www.anadarko.com under "Investor Relations" for reconciliations of the differences between any non-GAAP measure used in this presentation, including the appendix slides, and the most directly comparable GAAP financial measures. Also on our website at www.anadarko.com is a glossary of terms.

Cautionary Note to Investors - The U.S. Securities and Exchange Commission (SEC) permits oil and gas companies, in their filings with the SEC, to disclose only proved, probable and possible reserves that meet the SEC's definitions for such terms. We may use terms in this presentation, such as "resources," "net resources," "net discovered resources," "recoverable resources," and similar terms that the SEC's guidelines strictly prohibit us from including in filings with the SEC. U.S. Investors are urged to consider closely the oil and gas disclosures in our Form 10-K for the year ended December 31, 2015, File No. 001-08968, available from us at www.anadarko.com or by writing to us at: Anadarko Petroleum Corporation, 1201 Lake Robbins Drive, The Woodlands, Texas 77380 Attn: Investor Relations. You can also obtain this form from the SEC by calling 1-800-SEC-0330.

Successfully Navigating a Volatile Environment

- **Focus on Enhancing and Preserving Value**
- **Reduce Capital Program ~50% YOY**
- **Reduce Dividends**
- **Achieve Additional Cost Savings and Efficiency Gains**
- **Continue Active Monetization Program**
- **Reduce Net Debt**

2016 E&P INVESTMENTS(Billions)

SHORT CASH CYCLE

$1.5

~1 YEAR

- DJ Basin
- GOM Tiebacks
- TEN Startup

MID CASH CYCLE

$0.5

1 - 3 YEARS

- Delaware Basin
- GOM Appraisals

LONG CASH CYCLE

$0.5

3+ YEARS

- Shenandoah
- Colombia
- Côte d'Ivoire
- Mozambique

Note: All amounts are approximate

2016 Expectations

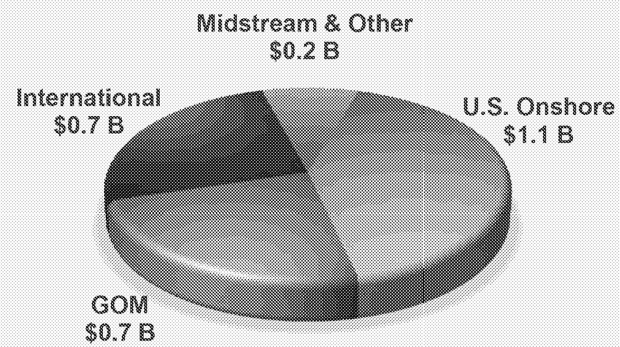
	2016E	2015	
CAPITAL[1] (BILLIONS)	$2.6 - $2.8	$5.4	~50%
SALES VOLUMES[2] (MMBOE)	282 - 286	292	~3%
OIL SALES VOLUMES[2] (MBOPD)	306 - 311	312	~Flat

[1] Excludes capital expenditures by WES
[2] Excludes all sales volumes associated with EOR, Bossier, PRB-CBM and East Chalk

- **$1.3 Billion Monetizations Closed**
  - $420 Million Soda Ash and Coal Royalties
  - $750 Million WES Transaction
  - $105+ Million East Chalk Divestiture
- **Additional Monetizations Under Way**

2016E CAPITAL PROGRAM

$2.6 - $2.8 BILLION*

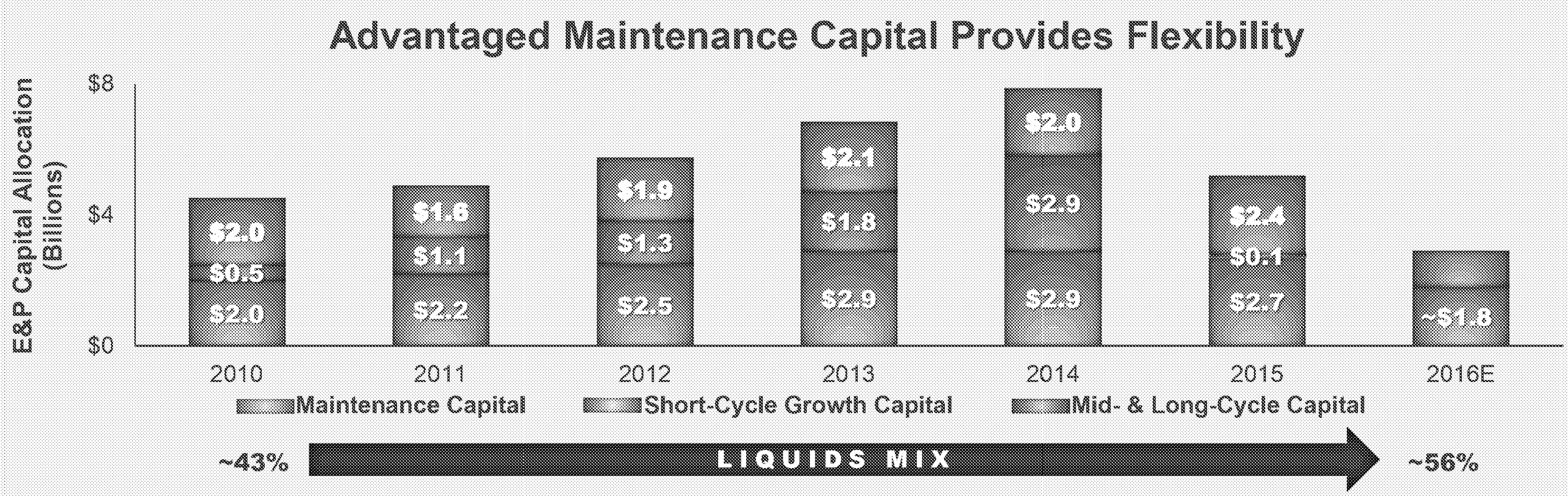


* Excludes capital expenditures by WES

APC-01753738

Benefits of a Balanced Portfolio

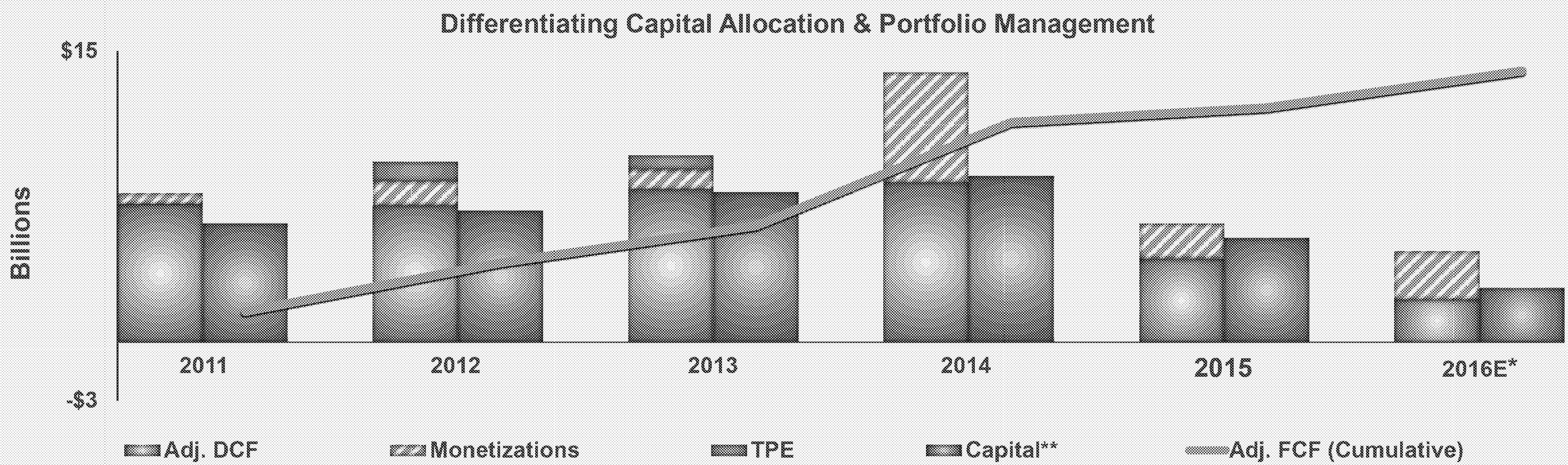
- **~18% Base Decline**
- **Leveraging IDUC Inventory**
- **Mega Project Contribution**
  - Full-Year Lucius Contribution
  - Heidelberg First Oil 1Q16
  - TEN First Oil Expected 3Q16



Note: Maintenance capital is defined as capital investments necessary to keep current-year sales volumes flat to previous year

Financial Discipline: Investing Within Cash Inflows

- **Increasing Flexibility**
  - 50% YOY Capital Reduction
  - 80% Dividend Reduction
  - Improving Cost Structure
- **Targeting up to $3 Billion Monetizations**
  - $1.3 Billion Monetizations Closed



** Based on consensus prices as of 5/2/2016: WTI $40/Bbl and HH $2.35/Mcf*
*** Excludes impact from Deepwater Horizon Event and Tronox*
Note: See Appendix for non-GAAP definitions and reconciliations

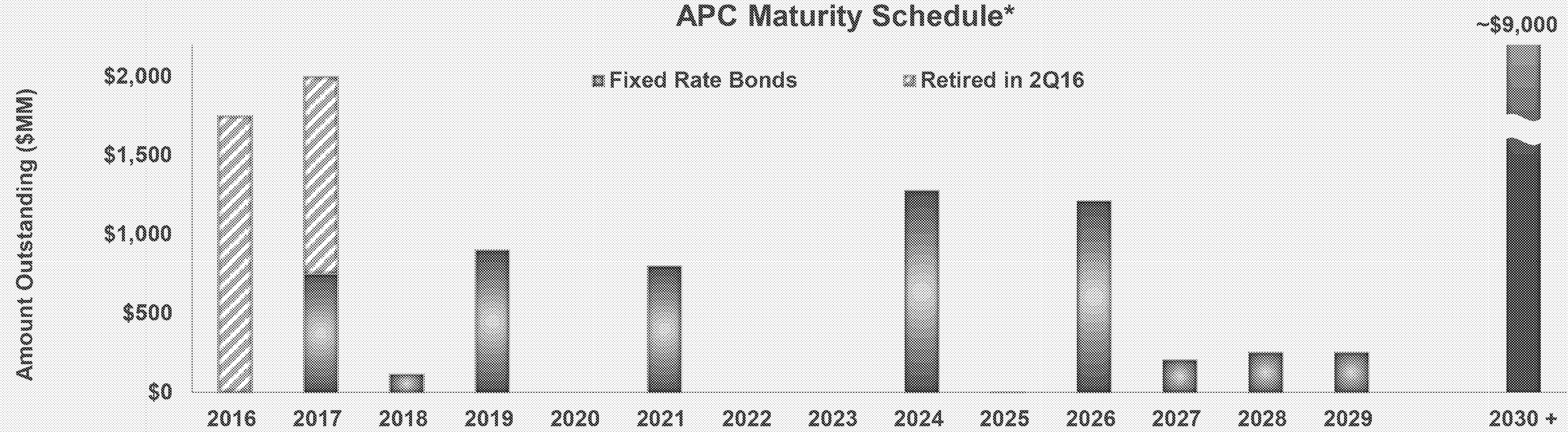
Maintaining Financial Strength

- **Ample Liquidity**
  - $3 Billion Cash-on-Hand 1Q16
  - $3 Billion 5-Year Revolving Credit Facility
  - $2 Billion 364-Day Facility
- **Substantial Flexibility**
- **Successfully Refinanced Near-Term Maturities**
  - Weighted Average Maturity Now 16+ Years
  - No Significant Maturities Until 2024

Investment-Grade Quality, Investment-Grade Approach

	Rating	Outlook
S&P	BBB	Negative
FITCH	BBB	Negative
MOODY'S	Ba1	Negative

APC Maturity Schedule*



* As of 5/2/2016

APC-01753741

Gulf of Mexico: Anadarko's Superior Value-Creation Model

Geologic Advantage → **Infrastructure Advantage** → **Commercial Advantage**

- **Proven Oil Finders***
  - 60+% Success Rate
- **Industry-Leading Project Management**
  - Leader in Standardization
  - Utilize Strategic Partnerships
  - Leverage Existing Infrastructure
- **Develop the Best, Divest the Rest***
  - $4+ Billion Monetizations
  - $2+ Billion Carried-Interest Agreements
- **Deep Inventory of Opportunities**

$16 Billion
Adjusted FCF
2006 - 2015

+

800+ MMBOE
Discovered Net Resources
Converting to Value

+

Future Exploration Success

*2006 - 2015 Results
Note: See Appendix for non-GAAP definitions

Low-Cost, High-Return Investment Opportunities

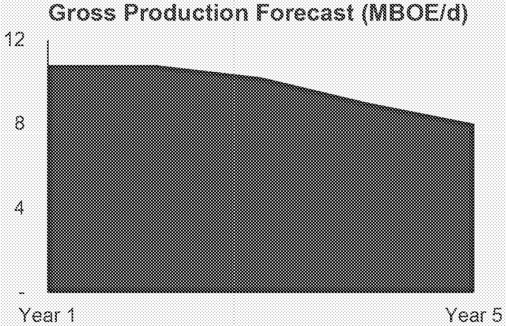
TIE-BACK ECONOMICS

30+ Opportunities

Gross EUR/Well	20 - 25 MMBOE
Development Cost	<$12/Bbl
Cycle-Time	~6 Months
BTAX10 Breakeven	<$15/Bbl

Facility Economics Further Enhanced Through PHAs

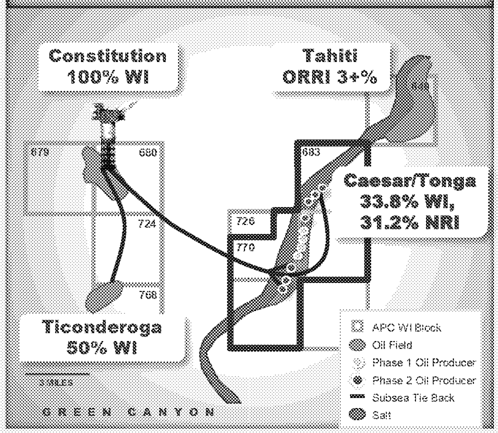
Tie-Back Type-Case
Gross Production Forecast (MBOE/d)



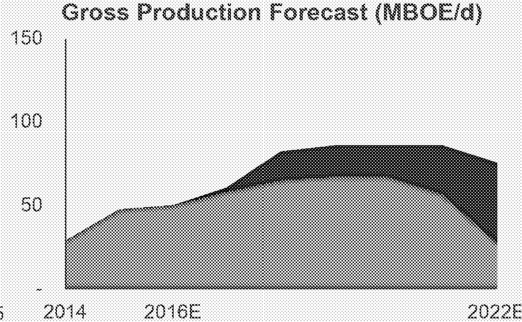
CAESAR/TONGA

2016 PLANNED ACTIVITY

2 Tiebacks
Phase 2 Facility Work



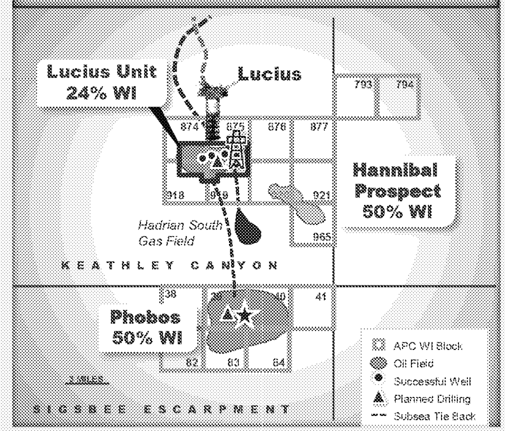
Caesar/Tonga
Gross Production Forecast (MBOE/d)



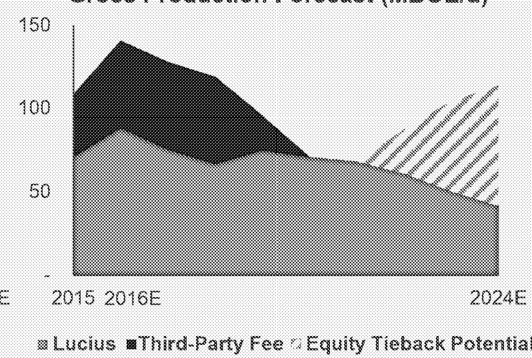
LUCIUS

2016 PLANNED ACTIVITY

1 Tieback



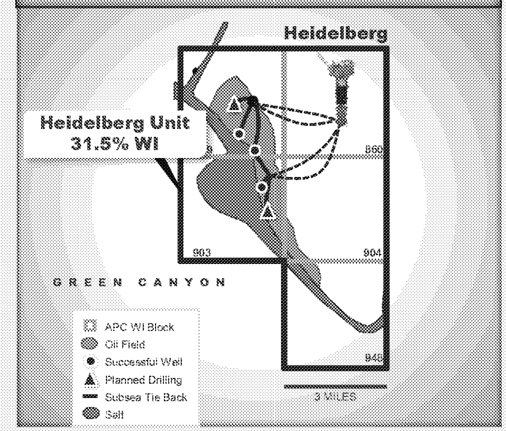
Lucius
Gross Production Forecast (MBOE/d)



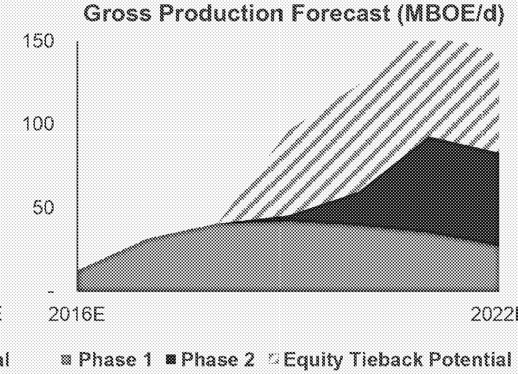
HEIDELBERG

2016 PLANNED ACTIVITY

Achieved First Oil
2 Additional Phase 1 Wells

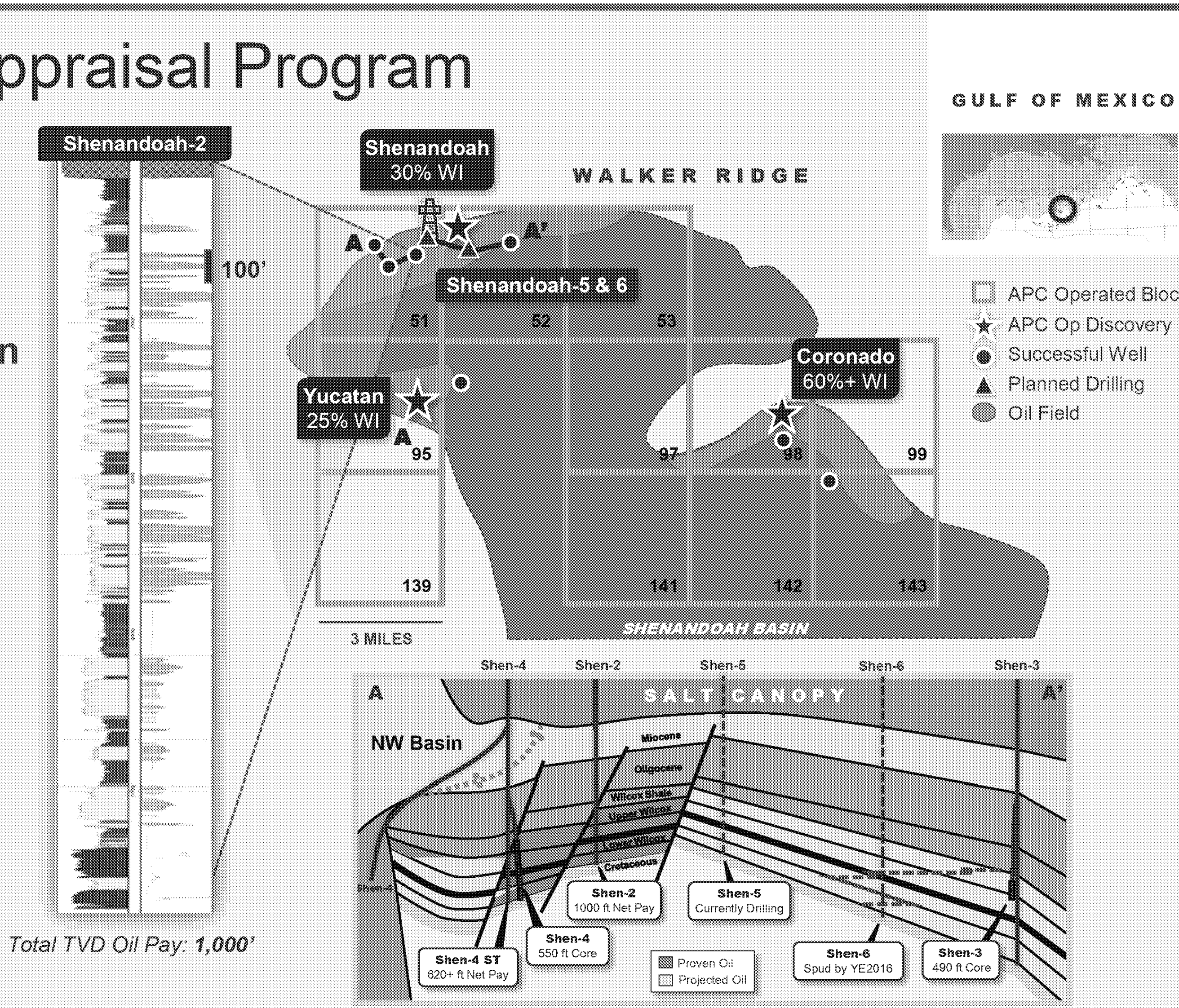


Heidelberg
Gross Production Forecast (MBOE/d)



Shenandoah: Active Appraisal Program

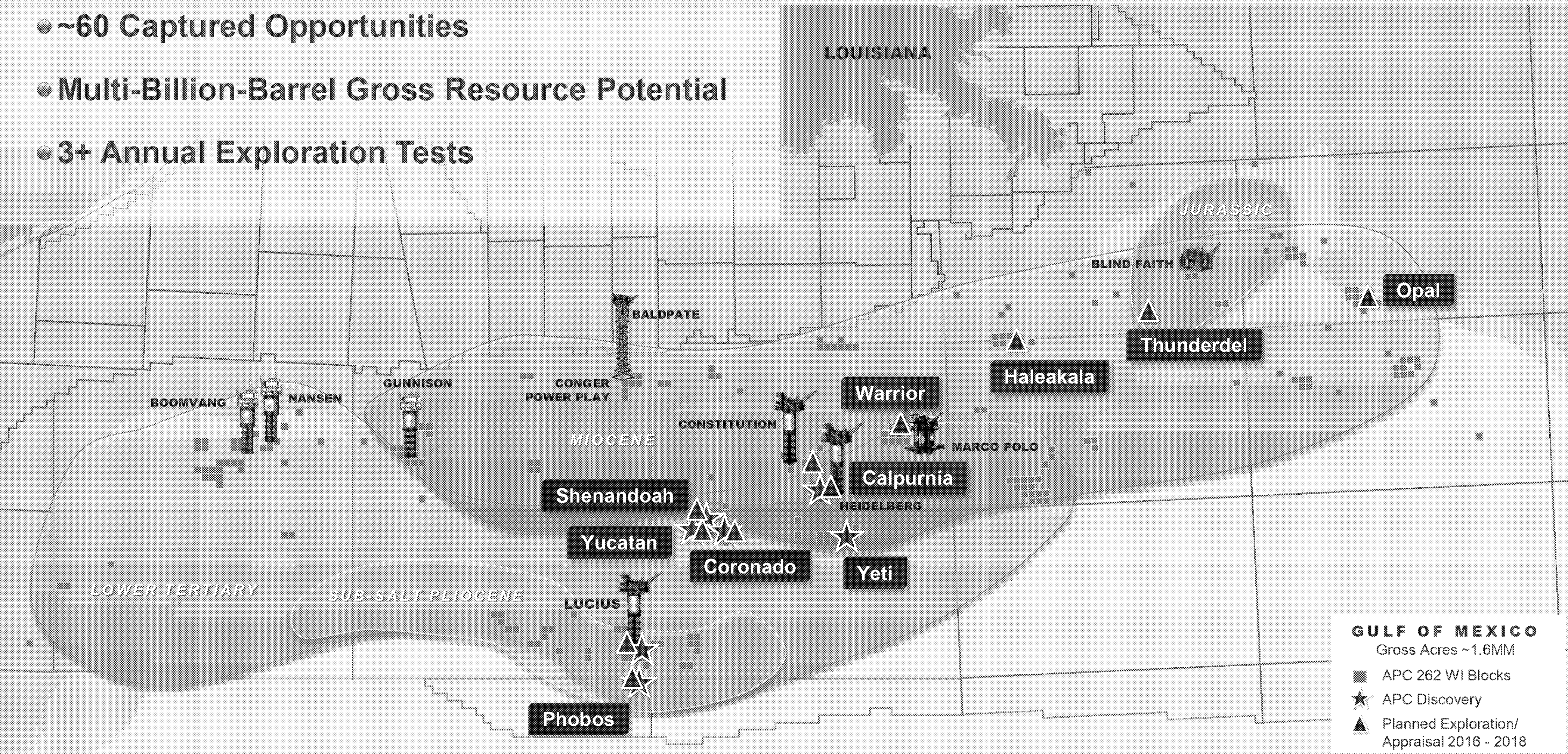
- **Significant Resource Potential**
  - Large Structural Closure
  - Thick Sandstone Packages
  - Excellent Reservoir & Fluid Properties
- **Strategic Position in Prolific Basin**
- **Finish Drilling Shenandoah-5**
- **Spud Shenandoah-6 4Q16**
- **Pre-FEED Work Under Way**



APC-01753744

Positioned for Continued Success

- ~60 Captured Opportunities
- Multi-Billion-Barrel Gross Resource Potential
- 3+ Annual Exploration Tests



Successfully Navigating a Volatile Environment

- Maintain Financial Discipline and Invest Within Cash Inflows
- Focus on Value
- Reduce Capital Spending and Cost Structure
- Position U.S. Onshore for the Future
- Capitalize on Portfolio Diversification and Flexibility
- Continue Active Monetization Program

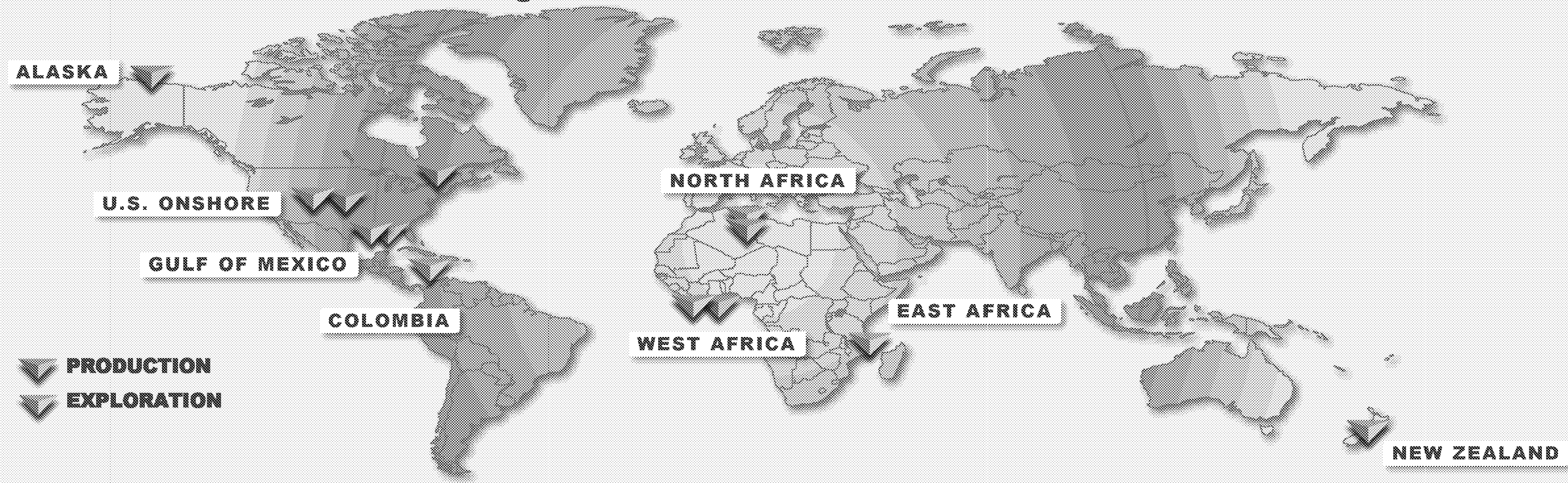


Exhibit 109

S&P Global
Market Intelligence

Anadarko Petroleum Corporation
NYSE:APC
Company Conference Presentation

Tuesday, June 28, 2016 1:40 PM GMT

Exhibit
461

Table of Contents

Call Participants

EXECUTIVES

Robert G. Gwin
President

ANALYSTS

Arun Jayaram
JP Morgan Chase & Co, Research Division

Unknown Analyst

Presentation

Arun Jayaram
JP Morgan Chase & Co, Research Division

Okay. We'll -- we're going to get started this morning. Very, very excited to have Anadarko Petroleum to lead off day 2 of our inaugural conference.

With me today is John Colglazier, who runs the Investor Relations group; Brian Kuck, in the first row; and Bob Gwin, who's the EVP and Chief Financial Officer of APC. He's also the Chairman of Western Gas, the general partner and one of the key value drivers of Anadarko. A bit unique about the strategy is to have that midstream component to it.

As many of you are aware, Anadarko is a diversified E&P with diversified operations in the U.S. with the U.S. franchise asset in the Wattenberg field and emerging position in the Delaware Basin as well as international operations in Algeria and Ghana and as well as a world-class exploration program.

With that, I'll turn it over to Bob. Bob?

Robert G. Gwin
President

Arun, thank you. Congratulations on the inaugural conference. We're really thrilled to be here and thrilled with the relationship with JPMorgan over time.

As Arun mentioned, we have a pretty substantial global portfolio, and what that gives us the opportunity to do is to deploy capital in a way that we think is relatively unique compared to the peers that you all would look to relative to an investment in Anadarko. We put on this slide a look at kind of how we think about capital allocation, how we think about the opportunities for capital allocation in our portfolio.

And the flexibility we have around capital allocation is we believe even more necessary in a market environment like the current one we're in, the one we've been in for the last, I don't know, 18 months or so. What we mean by that is that we're able to move capital around in a way that allows us to maximize, in our opinion, value creation and expose ourselves to the best economic returns available to us across our portfolio.

Traditionally, we would invest a significant amount of -- a significant majority of our capital in the U.S. onshore in shorter-cycle investments, where the cash cycle is a year or less, and a little bit less capital over the intermediate and longer term. And as you can see on the chart here on Slide 3, we're putting about 40% of our capital now into the intermediate and long term.

I'm going to talk, over the course of my comments this morning, about where that capital is going to work and why we think that's the better way to look at capital allocation in such a volatile environment. You can see also on this slide some of our objectives for 2016, and we'll talk about these and the progress against these objectives in a little greater detail.

So a variation of this slide we first introduced at the beginning of March at our annual investor conference. We laid out a pretty significant reduction in capital spending for the year, about a 50% cut year-over-year. It's actually 70% lower than our 2014 capital budget. But even though we cut capital that significantly, the nature of our portfolio and our low maintenance capital put us in a position to preserve volumes to a significant degree.

Our volumes were off ever so slightly this year. About 3% is what our guidance is telling us. But when we look at oil volumes, it's actually flat year-over-year as we bring on a couple of projects this year at Heidelberg and at TEN offshore Ghana and supplement that with a lot of momentum coming out of our U.S. onshore business in 2014 and 2015.

One of the important things we had to do during the course of the year was to ensure that we maintained the balance sheet strength and flexibility and how we're able to allocate capital and our access to capital. And so a big part of our program, as those of you that follow us know, is asset monetization program. On the bottom left of this Slide 4, I try to show you a little bit of where we are from an updated perspective.

Those of you that follow Anadarko probably notice that we announced a monetization of a small portion of our holdings in our Western Gas Equity Partners MLP, WGP, a couple of weeks ago. That was a little shy of $500 million. The other numbers on here, we've talked to you about in the past, $1.3 billion closed at the end of the first quarter. We have another $700 million that we're moving toward ensuring are closed in the second quarter. And since that ends day after tomorrow, I think it's fair to say we feel very good about that number at this stage. And when you add that to the Western Gas Equity Partners monetization, we're at about $2.5 billion year-to-date.

Now at the beginning of the year, we laid out a target of $2 billion to $3 billion in the aggregate, and we've raised that target now. That target did not include any Western Gas Partners monetizations, and so we've simply added the Western Gas monetization to the $2 billion to $3 billion target. Our new target is now $2.5 billion to $3.5 billion. And as we've talked about previously, there's a number of other monetizations that are underway and progressing that we would expect to move forward, at least from the closing of some of those, between now and the end of the year.

We've got a chart on here where you can see where we're allocating capital. This is another look at that -- at the numbers we showed you on the first page. The shorter cycle is primarily in the U.S. onshore. Some of the U.S. onshore is mid-cycle. Some of the U.S. GOM is shorter cycle and the balance is mid and long cycle and then the international spending, the midstream -- mid-cycle and the international is a combination of mid and long as well.

So I mentioned monetizations. And there's a lot of firms selling assets in the market today. This slide is intended to show you that the way we've approached our business and the financing of our business over the last several years, monetizations are a key part of it. We've consistently spent with our CapEx less than our cash inflows. Cash inflows being defined as our discretionary cash flow plus the proceeds from monetization. The monetizations are shown here in the hatch green area, and as you can see, year in and year out, we're monetizing a certain portion of our assets.

And generally speaking, we do this because we think it's the right way to build long-term value in the portfolio. The assets that we monetize generally are assets. They're not going to attract capital relative to the other higher-quality opportunities in the portfolio. And we feel that an important way to manage the portfolio is to sell and trim the assets that are good, solid economic assets but would not attract capital, therefore have an interest of potential purchasers of assets in the market and put us in a position of being able to redeploy those funds in higher value add, higher -- generally higher growth assets in our portfolio.

You can see on the chart, we've done that over the 6-year period. We've actually -- you go back a couple more years, I think it's been 8 years in a row, counting this year, where we will spend well within our cash inflows. And accordingly, by doing that, we've generated close to $15 billion of cumulative free cash flow over that time.

So we continue to do what we've done historically. We also, this year, are obviously very focused on not just reducing capital, as I mentioned previously, but we've reduced our dividends sharply by $450 million annually. That's about an 80% reduction in the dividend. We've also continued to cut cost. Regretfully, we had to announce some layoffs earlier this year. Those layoffs, along with some rebudgeting, the work that we've done around them, we believe, will deliver about $350 million in run rate reductions.

So in the aggregate, between the dividend cut and the cost reductions, it's about $800 million of reduced cash burden on the company. We're focused on the continuing monetizations. And with the lower spending, as you might imagine, we've put ourselves in a much stronger financial position.

And that position is somewhat captured here on Slide 6. We say we have ample liquidity. We had a lot of cash on hand at the end of the first quarter. We actually deployed that $3 billion to reduce near-term maturities, which are represented in the gray hatch area in the slide, in the graphic at the bottom of the

slide. In addition, we've got $5 billion of an unused credit facility. Some of the stuff we've done during the quarter is brought in additional cash. And when we announced second quarter numbers, obviously, we'll be able to show you a building cash, along with the reduction and continued reduction of indebtedness.

I also want to mention that the 2017 maturity, which is our nearest-term maturity, the remaining amount is $750 million, and we stated in a press release earlier this year that we expect to pay that down out of cash. And then we expect to continue to build cash during the year from asset sales, which will continue to improve the net debt position, and then we will opportunistically reduce the gross debt position through repurchases or retirements in the case, for instance, of the 2017 debt.

So I'll take a minute talking about just a few of our assets, and really, we want to focus on the places where we are putting capital, both in the near term. And then to the extent we were to expand our capital spending at all in the future in this kind of an environment, we want to show you where we would think we would put that money.

I mentioned a 50% reduction in aggregate capital spending this year. That number is even more pronounced in the U.S. onshore, where we're reducing our capital spending 70% year-over-year, sharply reducing our rig count, for instance, in the Wattenberg field, down to running an average of one rig per year and a completion crew there.

You can see that we've -- I mentioned on this slide that we've reduced our costs across the portfolio. We continue to improve efficiencies, which I'll talk about in a moment, and we entered the year with an intentionally drilled, but uncompleted, inventory of 230 wells. We didn't work off any of those during the first quarter.

At the beginning of the year, we thought we might work through up to 60, and I think that number is still a working progress as we see the production and the efficiency gains we've had during the year. Whether we work into that inventory to that degree remains to be seen and somewhat -- that's dependent upon the capital spending that we determine to pursue in the second half of the year.

So talk for a minute about our Wattenberg field in the DJ Basin. We put on here it's a world-class asset, and quite frankly, we believe it's just about the best unconventional asset in the world. Certainly, in North America, it competes economically with anything that's out there.

And it's able to do it for a couple of reasons, not just as a superb asset with improving efficiencies and improving cost structures as evidenced, for instance, in our ability to drive down well cost in the green graphic at the bottom of the page, but it generates material free cash flow every year. Even when we were in the high-growth mode, spending quite a bit more capital, as you see in the chart to the bottom left in blue, we were able to generate free cash flow. So it's a self-funding, high-growth asset in the right market environment.

In the current market environment, we felt it was appropriate to bring down the rig count and not to work through this inventory at relatively low profit dollars even though the rates of return are attractive. And we are leveraged here pretty significantly in these economics through a material minerals interest ownership. We own the minerals, so essentially, have royalty-free interest across approximately half our position here.

And many of you are familiar with Western Gas Partners story, our midstream -- our sponsored midstream MLP, where, through Western Gas, we have a significant economic interest in the midstream infrastructure here, from everything from the gathering opportunity -- so the gathering system to the process and opportunities to the longer haul transportation lines even to the frac trains at Mont Belvieu, where we're partners with Enterprise, so a tremendous, highly profitable, highly economic asset here. And I would expect to the extent we did expand capital spending within the increasing cash flow, this is a place where you'd see us begin to add rigs back, because clearly, the economic returns are superior.

The other place in the U.S. onshore that we're spending a fair amount of capital is the Delaware Basin. Now we think of this whereas the -- our work in the DJ is a shorter-cycle capital spend, we think of the Delaware as mid-cycle. And the reason for that is we're still in a mode of building out the infrastructure, doing some science with our drilling activity and beginning to plan for full-scale development when we move the plant -- pad drilling as early as next year.

You see at the bottom of the page that we've continued, throughout that period of time, to also improve efficiencies, drive down well cost. Clearly, we haven't optimized things in this part of the portfolio yet, but the progress is evident. And we expect that if you took just our activities today and solely move to a pad drilling environment, where we're leveraging fixed cross -- costs across a number of wells, that $6.2 million well cost would go down to $5.2 million. And I think that as we get into this program with greater progress like we have in the DJ, we would expect our efficiencies to drive down cost further.

The size of the resource here is phenomenal. While the DJ is also huge, we've got over 10 years of drilling inventory in the DJ with over 4,000 identified locations and 1.5 billion barrel-plus resource potential, we've already raised the resource potential for our Delaware position to north of 2 billion barrels. We more than doubled that recently. We think that -- that's just from the Wolfcamp A, for instance, and we believe there's substantial stacked pay potential across a significant amount of our position. Lots of science to do, lots of work to do here, but we feel like we're in a really good position to not only move to pad drilling in the near future but to leverage the infrastructure, where, again, our sponsored MLP is a significant partner here with some substantial capacity, both for Anadarko and for third parties.

We've had a lot of interest recently in our Gulf of Mexico position, and so I've put this in here right behind the DJ and the Delaware because we looked at our tieback opportunities in the Gulf of Mexico as comparable on a return basis and, in some way, superior in terms of a production profile. This is the third place we're really looking at spending some near-cycle capital.

We have about 30 tieback opportunities across the Gulf of Mexico, and of course, that's facilitated by some -- a very broad infrastructure portfolio that we own and control in the Gulf of Mexico and some facilities that are in some really good neighborhoods, like the Caesar/Tonga here, which ties into our Constitution spar Lucius, Heidelberg. K2 is not on the map because we've run out of space to put them all on here, but we have some substantial tieback opportunities at each one.

And the goal here, of course, is that once we have the fix cost infrastructure in place and that the costs of that infrastructure have been recaptured through our project sanctioning and our initial development plans, this becomes a leverageable asset, where point forward economics is the right way to look at the math. And if we can keep the production profile of these platforms at or near their capacity or, in some cases, expand the capacity of these platforms, as we've been able to do, we have tremendous leverage here to continue to extend the production profile well into the future.

I mentioned 30-plus points of opportunity, for instance. Well, we would only drill maybe 5 to 7 this year and something at or near that pace for the next several years because we're, of course, limited by the capacity of our infrastructure and of the offtake pipelines.

So this is what we believe is a very significant transparent growth profile for a number of years, tremendous returns of $60 oil. These things return greater than 70%. Those -- the kind of economics that are shown on the left side of the page here with -- between EURs and development cost of less than $12 per barrel, as all of you know, compete very favorably with the U.S. onshore portfolio, ours or anyone else's.

And importantly, if you look at that production profile, that average production profile to the bottom left, you can see that declines are relatively shallow. And so these conventional resources, we think, are a superb complement to the unconventional resources and the hyperbolic decline curves that we'll see in the U.S. onshore.

Rather than having to continue to feed the kitty in the U.S. onshore, regardless of the return potential or the investment case driven by commodity prices, in the case of the U.S. onshore, these things -- on the U.S. offshore, these things come on and run essentially flat for 12, 18, 24 months, dependent upon the individual reservoir, and provide tremendous economics relative to oil prices. So in the aggregate, you combine this with what we're doing in the U.S. onshore and we think that it produces a superior investment opportunity.

So I want to talk for a minute about our longer-cycle opportunities out there. Mozambique is clearly one of them. Mozambique, we continue to make progress there. Obviously, that progress has been somewhat slow.

The most important thing that we're focused on today is the legal and contractual framework, working with the government. Accordingly, the work with the government will set the pace of the project and set the time line to FID. And really, that's job one, to make sure that the contractual framework is in place so that as we and our partners invest capital in country, we know that it's going to result in economics that are predictable and dependable, and that when we put a dollar in, we'll know we get one point x dollars back out.

That progress, even though slow, is deliberate and continuous, and we continue to move forward. We're not estimating a time line for the completion of that, because obviously, somewhat -- some of it is out of our control in our work with the government. But as we're able to do that and as we're able to get these contractual agreements in place, then we'll be in a position to finalize taking our heads-up agreement for currently more than 8 million tons per annum of offtake and advance those toward sales and purchase agreements with a portfolio of high-quality offtake customers.

And obviously, that contractual portfolio then is the underpinning for a successful project financing. We expect to use about 2/3 leverage in that project. We've had numerous discussions, as you might imagine, with export credit agencies around the world, including, most recently, last week in London. We continue to be encouraged that the project financing community stands by ready to finance the project. But of course, that's dependent upon the contractual framework that they can reply upon in their credit analysis, and that contractual framework is, of course, reliant first upon getting the government agreements in place.

When these things move forward appropriately, we'll be able to take FID, and then of course, you would have a 4- to 5-year construction period before first cargoes. The nice thing about that, for those of you that follow global supply and demand around LNG, is that this time line intersects very, very nicely with what is expected to be a reversal in the global markets, where global demand for LNG begins to outstrip global supply and the current weakness that we've seen in the spot market would be reversed and a lot of project to generate materially incremental cash flow.

On an ongoing basis, this is not much capital exposed in 2016, nor has it been in recent years. I probably need to remind some of you that our net position here is a very -- in a very significant profit position, where, a couple of years ago, we netted $2.1 billion after tax in a sale of a portion of our interest to one of our new partners. And at that point in time, we had about $1 billion invested. So from an economic standpoint, very little net capital exposed through this project. And with tremendous upside and optionality available to Anadarko, we believe that risk return profile for a company of our size is very powerful.

Another area of longer-cycle spending is our exploration portfolio, and we put on this slide 3 areas that we think will -- that we know that we're focused on this year. That is in the Gulf of Mexico, offshore Côte d'Ivoire and offshore Colombia.

In Côte d'Ivoire, starting there, we have an appraisal well at Paon planned for this year. We'll follow that with a drillstem test. Through the appraisal and the drillstem test, we believe we will begin to gain the knowledge necessary to move toward a plan of development. To remind you, this is largely a gas development for a local market that provided the reservoir deliverability, proves up the way that we would hope through. Our work this year, we believe, could represent a very significant and attractive development opportunity. After -- in addition to the work at Paon, we have 2 exploration wells on 2 of our additional blocks here, Pelican and Rossignol, that we would expect to drill later this year.

The well would then move to Columbia to do some follow-up appraisal work, offshore Colombia, where we're in the stages of completing and interpreting the seismic from what was one of the largest 3D seismic shoots in the history of the world, over our very substantial 16 million acre position there. And it's in -- generated a lot of excitement upon -- around our exploration team.

The other area is the Gulf of Mexico. We have 2 exploration wells that we're viewing as potential tieback opportunities to our existing infrastructure with Phobos and Warrior. And in addition, we're very excited to be working toward completing the Shenandoah #5 well. Some of you may have heard some comments we've made in the past there. I don't have the log here, the #2 appraisal well, which had over 1,000 feet of net pay that we announced I think it was now a couple of years ago. But Shenandoah-5, at least in the uphole sections, we talked about the fact that it looked a lot like Shenandoah-2. A lot of enthusiasm around our activities here because of Shen-5. The results of Shen-5 have put as in a position where we clearly expect to drill Shen-6 later this year and continue with an appraisal program there, beginning to -- continuing to frame the aerial extent of the reservoir. Clearly, we know we have a lot of column. We know we have very attractive Mioecene-like sands. And now we need to determine the aerial extent of the reservoir so that we can move forward with our pre-FEED work and begin to conceptualize what a development opportunity would look like here.

We'll spend about $500 million of capital of our budget in exploration, in the aggregate offshore and onshore this year.

And one of the question we get sometimes is why, why spend money on exploration, especially when greenfield development cost more than the brownfield tieback opportunities. And so we put this slide together, as some of you have seen before, to try to show you the power of exploration when you're good at it for a company our size. Over the course of the last 10 years, we spent about $10 billion in the aggregate, so roughly $1 billion a year. Some years, it'd be less, $500 million, $600 million, $700 million, $800 million. I think the most we spent was probably $1.4 billion, $1.5 billion when we had a large appraisal program a few years back. But year in and year out, we've remained committed to our teams that have proven they are excellent at what they do, and it's paid off tremendously.

That $10 billion, we discovered around 6.5 billion barrels of net resources. We've been able to monetize over $14 billion of value from the discoveries and our exploration activities, either farming out or selling discoveries or selling down developments, like we were able to do at Lucius and Heidelberg, with tremendous capital opportunities. So as a sheer cash-on-cash profit, this has been a tremendous portfolio over the last 10 years. But in addition to that, we're left with north of 5 billion barrels of those discovered resources and about 250,000 barrels a day of our current production results from the discoveries of -- that were related to this $10 million spend.

So from a macro standpoint, we believe this is an area of great optionality for our shareholders, an area where we have clear competitive advantages and skill sets and it's an area that we're committed to continuing to invest in because it can drive a lot of value in the future, both on some of the things that I've mentioned and other opportunities that are listed here at the bottom of the page, where we've got lots of additional growth, either through new developments or tieback opportunities.

So in summary, it's a little bit of a cross-section of how we view the world, how we view it from a capital allocation standpoint, from an asset standpoint, the places we're putting money to work in 2016, we've got tremendous hope for the future. Obviously, we're fundamentally bullish over the longer term on commodity prices, given that we're investing in oil for the longer term and beyond just this current year. We think we've done the things necessary to reduce cost, reduce cash burdens on the business, improve financial flexibility, improve the credit profile of the company.

We've got a little work to do to continue to execute on monetizations through the year. To the extent we're able to do that, we apply monetizations toward the reduction of debt, either on a net or a gross basis. And to the extent we see additional cash flows through commodity price improvements through the end of the year, then we'll consider whether to increase the capital budget and, if so, where to put those dollars. And as I mentioned previously, probably the first place we would go do it is in the tremendous economic opportunities available in the DJ Basin and the Rockies.
And so Arun, with that, I know we have a few minutes left. I'm happy to take some Q&A.

Question and Answer

Arun Jayaram
JP Morgan Chase & Co, Research Division

If you do have a question, please raise your hand. On the front row, [indiscernible].

Unknown Analyst

Ex tieback opportunities, which obviously work at a lower oil price, for deepwater drilling, what would sort of price or price range you think you need to kind of make that economically viable?.

Robert G. Gwin
President

Great question, and I won't answer it directly because, frankly, the answer varies. It varies with the opportunity. Something like a Shenandoah is obviously tremendous resource potential, but the development plan could be from a relatively smaller spar opportunity to maybe multiple spars to something bigger that you might pursue. Because we have Coronado and Yucatan in the same mini-basin that are tremendous kind of in situ tieback opportunities for the future. We've looked at kind of a PV10 breakeven as a lot of people do in the onshore, and you're pretty close to it at -- well, at least at recent oil price, maybe not what we've seen since Brexit. But at recent oil prices, you are starting to look economic to something that's in that PV10 breakeven standpoint. But obviously, you wouldn't pursue economics in the Gulf of Mexico for a 10% rate of return. We have to focus on risk-adjusted rates of return, and accordingly, we're going to see something at a higher commodity price. One of the nice things is that in the current environment, with fewer of these projects out there, obviously, we have -- we believe we will have, as we work through a FEED process, some relatively good leverage with EPC contractors that would be more interested in pursuing our project on a one-off basis than they might be in a more robust time and, therefore, might be a little bit more aggressive on price. So too many moving pieces to answer the question directly, but we don't believe we're a long way off, relative to our forward look at oil prices, to consider greenfield. Now beyond Shenandoah, obviously, there are many things we're looking at. They're a little smaller. We're focusing on kind of longer tiebacks to existing infrastructure rather than greenfield developments, but it puts you in a position there and when you can drill 100 million barrel opportunities and things don't have to look at like, say, 200 million and 300 million and 400 million barrel opportunities to justify infrastructure.

Unknown Analyst

Could you talk about your view on your stake in WGP? You obviously sold 475 million not too long ago. Is that a level that we should consistently expect annually? And then is there an optimal level for that stake over time?

Robert G. Gwin
President

Sure. That's a great question. We've sold a little bit of it for the last 3 years, and my numbers won't be exact. But in 2014, it was 300-and-some-odd million. Last year, it was 600-and-some-odd million. This year, 475 million. So the number will probably move around some. We're constrained by how much we can sell efficiently because the float is not very great. For instance, after our most recent sale, we still own something like 78% of the equity in WGP. And we're very conscious of the fact that we don't want to bring enough paper to market that it causes the trading dynamics around the security to be abnormally negatively impacted, which is why we try to -- we spread these out over a multi-year period, and we obviously haven't been very aggressively selling. We've got north of $6 billion of value remaining even at the current equity price. Our expectations around growth in the DJ and the Delaware, which are Western Gas's 2 most prolific basins, as well cause us to have a pretty good idea, pretty transparent view of future growth at those MLPs. And so we -- obviously, we believe future value looks pretty good for those based on lots of market conditions. Setting the market conditions aside, just simply looking at the

performance expectations around volumes. So we'll continue to sell some of it over time. I don't think we'll be aggressive sellers. Certainly, we get opportunities to sell bigger chunks at points in time and probably negotiated transactions, given the attractiveness of the portfolio. But we've -- we kind of -- we're not in a hurry necessarily. We don't believe we're short cash or in any need to be aggressive on that front. And we're going to -- just going to try to be opportunistic over time, take a little bit off the table, ensure that security is positioned to trade well. And I think of it as being a responsible sponsor by taking a long-term view on the health of the entities and how they trade publicly rather than any short-term agenda. Thanks for the question. Yes?

Unknown Analyst

Just wondering if you can take a moment and talk about the regulatory environment in Colorado. I mean, the referendum is in everybody's mind, but if you could give an update as well.

Robert G. Gwin
President

Yes. We're obviously very involved there, paying a lot of attention, most significantly, aggressively continuing our education program, which was a process that we stood up in 2012, 2013 as we're heading toward the 2014 potential challenges and ballot initiatives there. And we have found a lot of traction with education. That disinformation and misinformation by those that are critical of activities in the area is -- falls by the wayside when our teams in Colorado and those of our partners are getting the word out around the truth behind the myths that are often talked about up there. Now there are certainly some potential -- well, some concerning ballot initiatives or potential ballot initiatives if they receive the requisite signatures by -- I forgot the date, in August. And we stand ready, obviously, to continue to fight aggressively to get the truth out and make sure that we have an educated electric. I think that the existing -- in particular, one of the existing ballot initiatives that deals with very aggressive setbacks from structures functionally puts oil and gas development in the state on hold. And though we believe there's a -- certainly, a low probability of it being on the ballot, we take it seriously and we'll continue to aggressively work against it should it be on there. It polls very poorly in the state, the lack of development, their -- the sheer economic impact on the state. Even with the slowdown like we've seen, the state's revenues obviously have had a material falloff. And it's really just a draconian dynamic for schools and funding and economics in the state of -- if oil and gas were to be restricted in a manner that, that particular initiative lays out. So it is -- it's concerning. We take it as a real threat, because obviously, it's a very important asset for us and for Noble and some others in the state. But by the same token, we believe that there is -- that the backdrop, just to fight those types of things, is very strong. And we and industry, together, we think -- it goes beyond industry. You look at homebuilders and the school boards and the Governor and the senators on both side of the aisle and -- I mean, anyone that actually -- the thinking people that pay attention to the impact on the state and pay attention on the actual need for such draconian restrictions, I think, see this in a clear light. And accordingly, we think that things will work out for the best over the course of the next few months and then through the fall, if we need to continue to fight it. Other questions?

Arun Jayaram
JP Morgan Chase & Co, Research Division

I think in the interest of time, we're going to have to cut it off there. Thanks a lot, Bob.

Robert G. Gwin
President
Thank you, Arun. Thanks for having us.